DOMINOS PIZZA INC
Form SC 13G/A
January 12, 2017

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE 13G

Under the Securities Exchange Act of 1934

(Amendment No: 8)

DOMINOS PIZZA INC.
--------------------------------------------------------
(Name of Issuer)

Common Stock
--------------------------------------------------------
(Title of Class of Securities)

25754A201
--------------------------------------------------------
(CUSIP Number)

December 31, 2016
--------------------------------------------------------
(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

[X] Rule 13d-1(b)
[ ] Rule 13d-1(c)
[ ] Rule 13d-1(d)

*The remainder of this cover page shall be filled out for a reporting person's initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934 ("Act") or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

CUSIP No. 25754A201

(1)Names of reporting persons. BlackRock, Inc.

(2) Check the appropriate box if a member of a group
(a) [ ]

(b) [X]

(3) SEC use only

(4) Citizenship or place of organization

Delaware

Number of shares beneficially owned by each reporting person with:

(5) Sole voting power

4796403

(6) Shared voting power

NONE

(7) Sole dispositive power

5384078

(8) Shared dispositive power

NONE

(9) Aggregate amount beneficially owned by each reporting person

5384078

(10) Check if the aggregate amount in Row (9) excludes certain shares

(11) Percent of class represented by amount in Row 9

11.2%

(12) Type of reporting person

HC

Item 1.

Item 1(a) Name of issuer:
-----------------------------------------------------------------------

DOMINOS PIZZA INC.

Item 1(b) Address of issuer's principal executive offices:
-----------------------------------------------------------------------

30 Frank Lloyd Wright Drive
Ann Arbor MI 48106

Item 2.

2(a) Name of person filing:
----------------------------------------------------------------------
BlackRock, Inc.

2(b) Address or principal business office or, if none, residence:
-----------------------------------------------------------------------
BlackRock Inc.
55 East 52nd Street
New York, NY 10055

2(c) Citizenship:
--------------------------------------------------------------------
See Item 4 of Cover Page

2(d) Title of class of securities:
-------------------------------------------------------------------

Common Stock

2(e) CUSIP No.:
See Cover Page

Item 3.

If this statement is filed pursuant to Rules 13d-1(b), or 13d-2(b) or (c), check whether the person filing is a:
[ ] Broker or dealer registered under Section 15 of the Act;
[ ] Bank as defined in Section 3(a)(6) of the Act;
[ ] Insurance company as defined in Section 3(a)(19) of the Act;
[ ] Investment company registered under Section 8 of the Investment Company Act of 1940;
[ ] An investment adviser in accordance with Rule 13d-1(b)(1)(ii)(E);
[ ] An employee benefit plan or endowment fund in accordance with Rule 13d-1(b)(1)(ii)(F);
[X] A parent holding company or control person in accordance with Rule 13d-1(b)(1)(ii)(G);
[ ] A savings associations as defined in Section 3(b) of the Federal Deposit Insurance Act (12 U.S.C. 1813);
[ ] A church plan that is excluded from the definition of an investment company under section 3(c)(14) of the Investment Company Act of 1940;
[ ] A non-U.S. institution in accordance with Rule 240.13d-1(b)(1)(ii)(J);
[ ] Group, in accordance with Rule 240.13d-1(b)(1)(ii)(K). If filing as a non-U.S. institution in accordance with Rule 240.13d-1(b)(1)(ii)(J), please specify the type of institution:

Item 4. Ownership

Provide the following information regarding the aggregate number and percentage of the class of securities of the issuer identified in Item 1.

Amount beneficially owned:

5384078

Percent of class

11.2%

Number of shares as to which such person has:

Sole power to vote or to direct the vote

4796403

Shared power to vote or to direct the vote

NONE

Sole power to dispose or to direct the disposition of

5384078

Shared power to dispose or to direct the disposition of

NONE

Item 5.

Ownership of 5 Percent or Less of a Class. If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than 5 percent of the class of securities, check the following [  ].

Item 6. Ownership of More than 5 Percent on Behalf of Another Person

If any other person is known to have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of, such securities, a statement to that effect should be included in response to this item and, if such interest relates to more than 5 percent of the class, such person should be identified. A listing of the shareholders of an investment company registered under the Investment Company Act of 1940 or the beneficiaries of employee benefit plan, pension fund or endowment fund is not required.

Various persons have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of the common stock of
DOMINOS PIZZA INC.
No one person's interest in the common stock of
DOMINOS PIZZA INC.
is more than five percent of the total outstanding common shares.

Item 7. Identification and Classification of the Subsidiary Which Acquired the Security Being Reported on by the Parent Holding Company or Control Person.

See Exhibit A

Item 8. Identification and Classification of Members of the Group

If a group has filed this schedule pursuant to Rule 13d-1(b)(ii)(J), so indicate under Item 3(j) and attach an exhibit stating the identity and Item 3 classification of each member of the group. If a group has filed this schedule pursuant to Rule 13d-1(c) or Rule 13d-1(d), attach an exhibit stating the identity of each member of the group.

Item 9. Notice of Dissolution of Group

Notice of dissolution of a group may be furnished as an exhibit stating the date of the dissolution and that all further filings with respect to transactions in the security reported on will be filed, if required, by members of the group, in their individual capacity.

See Item 5.

Item 10. Certifications
By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

Signature.

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

Dated: January 9, 2017
BlackRock, Inc.

Signature:  Spencer Fleming

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Name/Title Attorney-In-Fact

The original statement shall be signed by each person on whose behalf the statement is filed or his authorized representative. If the statement is signed on behalf of a person by his authorized representative other than an executive officer or general partner of the filing person, evidence of the representative's authority to sign on behalf of such person shall be filed with the statement, provided, however, that a power of attorney for this purpose which is already on file with the Commission may be incorporated by reference. The name and any title of each person who signs the statement shall be typed or printed beneath his signature.

Attention: Intentional misstatements or omissions of fact constitute Federal criminal violations (see 18 U.S.C. 1001).

Exhibit A

Subsidiary

BlackRock (Luxembourg) S.A.
BlackRock (Netherlands) B.V.
BlackRock (Singapore) Limited
BlackRock Advisors (UK) Limited
BlackRock Advisors, LLC
BlackRock Asset Management Canada Limited
BlackRock Asset Management Ireland Limited
BlackRock Asset Management Schweiz AG
BlackRock Capital Management
BlackRock Financial Management, Inc.
BlackRock Fund Advisors
BlackRock Fund Managers Ltd
BlackRock Institutional Trust Company, N.A.
BlackRock International Limited
BlackRock Investment Management (Australia) Limited
BlackRock Investment Management (UK) Ltd
BlackRock Investment Management, LLC
BlackRock Japan Co Ltd
BlackRock Life Limited
FutureAdvisor, Inc.

*Entity beneficially owns 5% or greater of the outstanding shares of the security class being reported on this Schedule 13G.

Exhibit B

POWER OF ATTORNEY

The undersigned, BLACKROCK, INC., a corporation duly organized under the laws of the State of Delaware, United States (the "Company"), does hereby make, constitute and appoint each of Matthew Mallow, Chris Meade, Howard Surloff, Dan Waltcher, Georgina Fogo, Charles Park, Enda McMahon, Carsten Otto, Con Tzatzakis, Karen Clark, Andrew Crain, Herm Howerton, David Maryles, Daniel Ronnen, John Stelley, John Ardley, Maureen Gleeson and Spencer Fleming acting severally, as its true and lawful attorneys-in-fact, for the purpose of, from time to time, executing in its name and on its behalf, whether the Company is acting individually or as representative of others, any and all documents, certificates, instruments, statements, other filings and amendments to the foregoing (collectively, "documents") determined by such person to be necessary or appropriate to comply with ownership or control-person reporting requirements imposed by any United States or non-United States governmental or regulatory authority, Including without limitation Forms 3, 4, 5, 13D, 13F, 13G and 13H and any amendments to any of the Foregoing as may be required to be filed with the Securities and Exchange Commission, and delivering, furnishing or filing any such documents with the appropriate governmental, regulatory authority or other person, and giving and granting to each such attorney-in-fact power and authority to act in the premises as fully and to all intents and purposes as the Company might or could do if personally present by one of its authorized signatories, hereby ratifying and confirming all that said attorney-in-fact shall lawfully do or cause to be done by virtue hereof. Any such determination by an attorney-in-fact named herein shall be conclusively evidenced by such person's execution, delivery, furnishing or filing of the applicable document.

This power of attorney shall expressly revoke the power of attorney dated 1st day of October, 2015 in respect of the subject matter hereof, shall be valid from the date hereof and shall remain in full force and effect until either revoked in writing by the Company, or, in respect of any attorney-in-fact named herein, until such person ceases to be an employee of the Company or one of its affiliates.

IN WITNESS WHEREOF, the undersigned has caused this power of attorney to be executed as of this 8th day of December, 2015.

BLACKROCK, INC.

By:_ /s/ Chris Jones
Name: Chris Jones
Title: Chief Investment Officer

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, tax, 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 its electric transmission and certain gas transmission and storage revenues, the Utility’s base revenues are “decoupled” from its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, 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, who generally represent the overall interests of residential customers, as well as a myriad of other intervenors who represent other business, community, customer, environmental, and union interests. (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. (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.)

11

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. The CPUC has authorized the Utility’s capital structure through 2019, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also set the authorized ROE through 2017 at 10.40% and 10.25% beginning on January 1, 2018 and reset the cost of debt to 4.89%. The CPUC previously adopted an adjustment mechanism to allow the Utility’s capital structure and ROE to be adjusted if the utility bond index changes by certain thresholds on an annual basis. The Utility expects to submit its next cost of capital application to the CPUC on or about April 22, 2019.

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 proposed 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 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.)

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 BCPPs based on long-term demand forecasts. In October 2015, the CPUC approved the Utility’s most recent BCPP. 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 suspended certain elements of its current BCPP 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 BCPP to further refine how it manages certain elements of its procurement activity and provide detail of its sales framework. The updated BCPP would be effective upon CPUC approval.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved BCPPs 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 the energy resource recovery account. (See Note 3 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 14 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.

13

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.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon's two nuclear power reactor units by 2024 and 2025. The CPUC:

- deferred consideration of replacement resources to the CPUC's Integrated Resource Planning proceeding;
- authorized rate recovery for up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program;
- authorized rate recovery for an employee retraining program of $11.3 million requested by the Utility;
- rejected rate recovery of the proposed $85 million for the community impacts mitigation program on the grounds that rate recovery for such a program requires legislative authorization;
- authorized rate recovery of $18.6 million of the total Diablo Canyon license renewal cost of $53 million and rate recovery of canceled project costs equal to 100% of direct costs incurred prior to June 30, 2016, and 25% of direct costs incurred after June 30, 2016, based on a provision of the settlement agreement among the Utility, the Joint Parties, and certain other parties that the Utility filed with the CPUC in May 2017; and
- approved the amortization of the book value for Diablo Canyon consistent with the Diablo Canyon closure schedule.

On March 7, 2018, the Utility submitted a request to the NRC to withdraw its Diablo Canyon license renewal application. On April 16, 2018, the NRC granted the Utility's request to withdraw its license renewal application.

On November 29, 2018, in response to SB 1090, the CPUC issued its decision addressing the key remaining goals of the Diablo Canyon joint proposal agreement, including:

- approving the community impact mitigation settlement of $85 million, originally proposed in the joint settlement agreement;
-

deferring implementation to its Integrated Resource Planning to ensure that there is no increase in GHG emissions as a result of the Diablo Canyon retirement; and

- approving full funding of the $352.1 million Diablo Canyon employee retention program, originally proposed in the joint settlement agreement.

On February 8, 2019, the CPUC approved the Utility's request to implement SB 1090, effective as of January 1, 2019, which includes full funding for the community impact mitigation program and employee retention program.

For costs related to Asset Retirement Obligations see "Nuclear Decommissioning Obligation" in Note 2 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 2018 represented by each major electric resource, and further discussed below.

Total 2018 Actual Electricity Generated and Procured - 48,832 GWh [1]:

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 33.5 % | |
| Small Hydroelectric | 1.5 % | |
| Large Hydroelectric | 12.1 % | |
| Fossil fuel-fired | 11.6 % | |
| Solar | 0.6 % | |
| Total | | 59.3 % |
| Qualifying Facilities | | |
| Renewable | 0.5 % | |
| Non-Renewable | 4.4 % | |
| Total | | 4.9 % |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.1 % | |
| Large Hydroelectric | — % | |
| Total | | 0.1 % |
| Other Third-Party Purchase Agreements | | |
| Renewable | 36.2 % | |
| Non-Renewable | 0.6 % | |
| Large Hydroelectric | 9.5 % | |
| Total | | 46.3 % |
| Others, Net [2] | (10.6)% | (10.6)% |
| Total [3] | | 100 % |

[1] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.

(2) Mainly comprised of net CAISO open market purchases.
(3) Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

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. During 2018, 38.9% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 28%. Approximately 36% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (0.5%), the Utility's small hydroelectric facilities (1.5%), and the Utility's solar facilities (0.6%).

The total 2018 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales | |
|---|---|---|---|
| Biopower | 2,161 | 4.4 | % |
| Geothermal | 1,816 | 3.7 | % |
| Wind | 4,861 | 10 | % |
| RPS-Eligible Hydroelectric | 1,324 | 2.7 | % |
| Solar | 8,839 | 18.1 | % |
| Total | 19,001 | 38.9 | % |

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.

As of November 2018, the Utility had met and exceeded its 2018 interim storage targets and had approximately 35 MW remaining to procure to meet the total storage targets established by the CPUC. This outcome may change in the future if projects under contract are terminated or if projects that have been approved by the CPUC are rejected on rehearing.

In 2018, the CPUC approved two proposals for the Utility to own incremental battery storage facilities to be constructed by a third party. The Llagas Energy Storage Project is a 20 MW project scheduled to come online in 2021. The Moss Landing Project is a 182.5 MW project scheduled to come online by the end of 2020. In addition, the Utility currently owns or operates three battery storage facilities, each less than 10 MW.

Owned Generation Facilities

At December 31, 2018, 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 14 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2018, 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 84 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, 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 approximately 20% are underground and approximately 80% are overhead), 50 transmission switching substations, and 769 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 2016 to 2018 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 2018, 2017 and 2016.

| | 2018 | 2017 | 2016 |
|---|---|---|---|
| Customers (average for the year) | 5,428,318 | 5,384,525 | 5,349,691 |
| Deliveries (in GWh) [(1)] | 79,774 | 82,226 | 83,017 |
| Revenues (in millions): | | | |
| Residential | $ 5,051 | $ 5,693 | $ 5,409 |
| Commercial | 4,908 | 5,431 | 5,396 |
| Industrial | 1,532 | 1,603 | 1,525 |
| Agricultural | 1,234 | 1,069 | 1,226 |
| Public street and highway lighting | 72 | 79 | 80 |
| Other [(2)] | (720 ) | (294 ) | (68 ) |
| Subtotal | 12,077 | 13,581 | 13,568 |
| Regulatory balancing accounts [(3)] | 636 | (344 ) | 297 |
| Total operating revenues | $ 12,713 | $ 13,237 | $ 13,865 |
| Selected Statistics: | | | |
| Average annual residential usage (kWh) | 5,772 | 6,231 | 6,115 |
| Average billed revenues per kWh: | | | |
| Residential | $ 0.1838 | $ 0.1936 | $ 0.1887 |
| Commercial | 0.1627 | 0.1716 | 0.1716 |
| Industrial | 0.1010 | 0.1055 | 0.0990 |
| Agricultural | 0.1968 | 0.2041 | 0.1814 |
| Net plant investment per customer | $ 7,950 | $ 7,486 | $ 7,195 |

(1) These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
(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 80% 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 that the Utility has a power purchase agreement with 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 2018, the Utility purchased approximately 287,000 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 15% of the total natural gas volume the Utility purchased during 2018.

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, 2018, the Utility's natural gas system consisted of approximately 43,100 miles of distribution pipelines, over 6,400 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 firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company 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. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas system in the area of Daggett, California. (For more information regarding the Utility's natural gas transportation agreements, see Note 14 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. Changes to gas storage safety requirements by DOGGR have led the Utility to develop and propose in its 2019 GT&S rate case application a natural gas storage strategy which includes the discontinuation (through closure or sale) of operations at two gas storage fields. (For more information, see "Regulatory Matters" in Item 7. MD&A.)

In 2018, 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 2016 through 2018 (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 2018, 2017 and 2016.

| | 2018 | 2017 | 2016 |
|---|---|---|---|
| Customers (average for the year)[1] | 4,495,279 | 4,467,657 | 4,442,379 |
| Gas purchased (MMcf) | 219,061 | 234,181 | 208,260 |
| Average price of natural gas purchased | $ 2.02 | $ 2.30 | $ 1.83 |
| Bundled gas sales (MMcf): | | | |
| Residential | 156,917 | 160,969 | 149,483 |
| Commercial | 51,357 | 50,329 | 46,507 |
| Total Bundled Gas Sales | 208,274 | 211,298 | 195,990 |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | $ 2,042 | $ 2,298 | $ 1,968 |
| Commercial | 537 | 541 | 439 |
| Other | 75 | (25 ) | 149 |
| Bundled gas revenues | 2,654 | 2,814 | 2,556 |
| Transportation service only revenue | 1,151 | 976 | 800 |
| Subtotal | 3,805 | 3,790 | 3,356 |
| Regulatory balancing accounts [2] | 242 | 221 | 446 |
| Total operating revenues | $ 4,047 | $ 4,011 | $ 3,802 |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 38 | 38 | 36 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | $ 12.67 | $ 14.27 | $ 13.10 |
| Commercial | 9.04 | 11.36 | 9.45 |
| Net plant investment per customer | $ 3,417 | $ 3,093 | $ 2,808 |

[1] These amounts include natural gas provided to direct access customers and CCAs who procure their own supplies of natural gas.
[2] These amounts represent revenues authorized to be billed.

20

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.” 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. 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. The CPUC is required to issue an order implementing the expansion by June 1, 2019.

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.

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 NEM, which allows self-generating customers 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. The CPUC has indicated that it intends to commence a new proceeding to revisit its rules related to NEM customers in 2019.

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, generally through eminent domain. These same entities may, and sometimes do, construct duplicate distribution facilities to serve existing or new Utility customers.

The effect of such types of retail competition generally is to reduce the amount of electricity purchased by customers from the Utility.

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.

(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.

21

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 $CO_2$ 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 14 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, 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 14 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, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG 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 led to significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. In light of the policy reversal 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.

State Regulation

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. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 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 natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. 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. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters 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 emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects.

SB 32 (2016) requires that CARB ensures a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. In 2017, AB 398 extended the cap-and-trade program to 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 and accelerates the state's 50% RPS target to December 31, 2026, increases the RPS target to 60% by December 31, 2030, and further amends 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 2018, 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 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 2017, the most recent data available, totaled about
46 million metric tonnes of $CO_2$ equivalent, more than three-quarters of which came from customer natural gas use. The following table shows the 2017 GHG emissions data the Utility reported to the CARB under AB 32. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes $CO_2$) |
|---|---|
| Fossil Fuel-Fired Plants [(1)] | 2,292,309 |
| Natural Gas Compressor Stations and Storage Facilities [(2)] | 269,133 |
| Distribution Fugitive Natural Gas Emissions | 630,249 |
| Customer Natural Gas Use [(3)] | 38,202,174 |

(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 $CO_2$ emissions rate associated with the electricity delivered to customers in 2017 as compared to the national average for electric utilities:

| | Amount (pounds of $CO_2$ per MWh) |
|---|---|
| U.S. Average [(1)] | 998 |
| Pacific Gas and Electric Company [(2)] | 210 |

(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 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 2017. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2017 | 2016 |
|---|---|---|
| Total NOx Emissions (tons) | 155 | 141 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ | 14 | 13 |
| $SO_2$ | 0.001 | 0.001 |

24

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 have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Second Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, in 2010, the California Water Board adopted a policy on once-through cooling that 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. 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 paid an annual interim mitigation fee beginning in 2017, which it will continue to pay 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 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 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, 2017 through May 31, 2018, totaled approximately $25 million and is currently under review by the DOE. Amounts reimbursed by DOE are refunded to customers through rates. A new settlement agreement, for costs through 2019 was executed in March 2017. 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 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.

25

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;
- 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;
- the ability to obtain Bankruptcy Court approval with respect to 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;
- potential for an increase in general unsecured claims as a result of the rejection of any executory contracts or unexpired leases as permitted under the Bankruptcy Code;
- 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 commitments outlined in the Utility's 2020 GRC 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 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;
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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.

26

PG&E Corporation and the Utility will also 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 will 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 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:

- sell assets outside the normal course of business;
- make capital investments outside the normal course of business;
- consolidate or merge or 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 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 may experience increased levels of employee attrition, and their employees will likely 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 services 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 develop and 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 have 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. The Bankruptcy Code gives PG&E Corporation and the Utility the exclusive right to file a plan of reorganization for 120 days after the filing and, subject to extension for cause, up to a maximum of 18 months from the Petition Date, and prohibits creditors, equity security holders and others from proposing a plan of reorganization during this period. PG&E Corporation and the Utility have currently retained the exclusive right to file a plan of reorganization until at least May 29, 2019. If that right is terminated, however, or the exclusivity period is not extended or expires, there could be 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.

Accordingly, no assurance can be provided as to the length of time during which the Chapter 11 Cases will be pending, whether a consensual or other plan of reorganization can be successfully developed and consummated, what the terms of any reorganization of PG&E Corporation and the Utility may be, and what effect any such plan or reorganization would have on the capital structure (or any part thereof) of 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.

If PG&E Corporation and the Utility are not able to develop and consummate a consensual plan of reorganization within the exclusivity period, one or more third parties may propose a competing plan of reorganization. PG&E Corporation and the Utility may have limited ability to prevent an alternative plan of reorganization from being approved by the Bankruptcy Court, even if PG&E Corporation and the Utility do not believe such plan is in their best interest and the best interests of their stakeholders. Even if PG&E Corporation and the Utility are successful in obtaining confirmation of a plan of reorganization following the expiration of their exclusivity period, the process may 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 a prolonged restructuring would 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;

- 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. 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. As a result of the Bankruptcy Court's interim approval of the DIP Credit Agreement on January 31, 2019 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 PG&E Corporation and the Utility. As of February 28, 2019, 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 are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all. For more information on the DIP Credit Agreement, see Note 4 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 will face uncertainty regarding the adequacy of their liquidity and capital resources during the pendency of the Chapter 11 Cases, and will 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. 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 4 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.

PG&E Corporation and the Utility may not be able to obtain exit financing to, among other things, repay borrowings under the DIP Credit Agreement, and even if they are able to obtain such exit financing, the agreement governing such exit financing may significantly restrict PG&E Corporation's and the Utility's financing and operational flexibility. The ability of PG&E Corporation and the Utility to emerge from bankruptcy will likely depend on obtaining financings from a number of potential sources, and there can be no assurance that any such financings or other potential sources can be obtained expeditiously or on favorable terms, if at all.

It is expected that the DIP Credit Agreement will be repaid using, in whole or in part, the proceeds from borrowings under exit financings. PG&E Corporation's and the Utility's ability to obtain such exit financing will depend on, among other things, the timing and outcome of various ongoing matters in the Chapter 11 Cases, their business, operations and financial condition, and market conditions. There can be no assurance that PG&E Corporation and the Utility will be able to obtain such exit financings on reasonable economic terms, or at all. If exit financing cannot be obtained, they may not be able to repay the DIP Credit Agreement at maturity or emerge from bankruptcy. Any exit financing that PG&E Corporation and the Utility are able to obtain may include a number of significant restrictive or financial covenants which could impair their financial and operational flexibility and make it difficult to react to market conditions and satisfy their ongoing capital needs and unanticipated cash requirements.

The ability of PG&E Corporation and the Utility to emerge from bankruptcy will likely depend on proceeds received from a number of potential sources. These potential sources may include financings in the capital and credit markets, securitization, proceeds of asset sales or other dispositions, and other potential sources. The ability to execute on any such financings or other potential sources will be subject to a variety of factors, many of which will be beyond the control of PG&E Corporation and the Utility, and may require consent or other action of federal and state regulators (including the FERC and the CPUC), the state legislature and executive branch, the Bankruptcy Court, other governmental entities, and other potential sources of third-party financing. There can be no assurance that any such financings or other potential sources can be obtained expeditiously or on favorable terms, if at all.

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 a going concern. PG&E Corporation and the Utility are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in 2018 and 2017. 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 a going concern. PG&E Corporation and the Utility are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in 2018 and 2017. 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. 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 1 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 and 2017 Northern California wildfires, 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 and 2017 Northern California wildfires, notwithstanding the commencement of the Chapter 11 Cases. As detailed below in Note 13 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 and 2017 Northern California wildfires 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 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, 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. Among other things, it is uncertain at this time as to the number of wildfire-related claims that will be filed in the Chapter 11 Cases, the number of current and future claims that will be settled in a plan of reorganization, how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed, and the impact that historical settlement values for wildfire claims may have on the estimation of wildfire liability in the Chapter 11 Cases.

Further, the Utility could be subject to material fines or penalties if the CPUC or any law enforcement agency brought an enforcement action, including a criminal proceeding, and determined that the Utility failed to comply with applicable laws and regulations. Such actions would not be subject to the automatic stay.

31

As described below in Note 13 of the Notes to Consolidated Financial Statements in Item 8, based on information made available by the California Department of Insurance, insurers have received an aggregate amount of approximately $18.4 billion of insurance claims made as of the dates noted below related to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility expect that additional claims have been submitted and will continue to be submitted to insurers, particularly with respect to the 2018 Camp fire. These claims reflect insured property losses only. The $18.4 billion of insurance claims described below does not account for uninsured or underinsured property losses, interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses or other costs, such as potential punitive damages, fines or penalties, or damages for claims related to the 2018 Camp fire and 2017 Northern California wildfires that have not manifested yet ("future claims"), each of which could be significant and could materially affect the financial condition, results of operations, liquidity, and cash flows of PG&E Corporation and the Utility. The scope of all claims related to the 2018 Camp fire and 2017 Northern California wildfires is not known at this time because of the applicable statutes of limitations under California law. 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 PG&E Corporation or the Utility were to be found liable for certain or all of the costs, expenses and other losses described above with respect to the 2018 Camp fire and 2017 Northern California wildfires, the amount of such liability could exceed $30 billion, which amount does not include potential punitive damages, fines and penalties or damages related to future claims. In certain circumstances, PG&E Corporation's and the Utility's liability could be substantially greater than such amount. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

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, 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 and the Utility and the treatment of such claims in the Chapter 11 Cases.

For more information about the 2018 Camp fire and 2017 Northern California wildfires, see "2018 Camp fire and 2017 Northern California wildfires" in Note 13 of the Notes to Consolidated Financial Statements in Item 8.

PG&E Corporation and the Utility are the subject of lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions in connection with the 2018 Camp fire and 2017 Northern California wildfires.

PG&E Corporation and the Utility are the subject of a number of lawsuits that have been filed against PG&E Corporation and the Utility in Sonoma, Napa and San Francisco Counties' Superior Courts in connection with the 2018 Camp fire and 2017 Northern California wildfires, several of which seek to be certified as class actions, asserting damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. Insurance carriers who have made payments to their insureds for property damage arising out of the 2017 Northern California wildfires have filed 48 subrogation complaints in the San Francisco 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. Insurance carriers have filed 37 similar subrogation complaints with respect to the 2018 Camp fire in the Sacramento County Superior Court. Further, PG&E Corporation and the Utility have been named as defendants in securities class action litigation related to the 2017 Northern California wildfires and 2018 Camp fire.

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. However, 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 or the Bankruptcy Court could lift the automatic stay with respect to such pre-petition obligations. Further, PG&E Corporation and the Utility could be the subject of additional investigations, citations, fines or enforcement actions in connection with the 2018 Camp fire and 2017 Northern California wildfires. The wildfire litigation could take a number of years to be resolved through the Chapter 11 process because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The ultimate number and allowed amount of such claims are not presently known and cannot be reasonably estimated at this time.

If PG&E Corporation or the Utility were to be found liable for any punitive damages or subject to fines or penalties in connection with the 2018 Camp fire and 2017 Northern California wildfires, their financial condition, results of operations, liquidity, and cash flows could be materially affected.

If PG&E Corporation or the Utility were to be found liable for any punitive damages or subject to fines or penalties, the amount of such punitive damages, fines and penalties 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. 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.

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 and 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. PG&E Corporation and the Utility have $842 million of insurance coverage for liabilities, including wildfire events, for the period from August 1, 2017 through July 31, 2018, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. During the third quarter of 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 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 and the Utility may not be able to recover the full amount of their insurance. 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 2017 Northern California wildfires will greatly exceed their available insurance.

In addition, it could take a number of years before the Utility's final liability in connection with the 2018 Camp fire and 2017 Northern California wildfires is known and the Utility could apply for recovery of costs in excess of insurance. While the CPUC has authorized the Utility to track certain wildfire costs in its WEMA, the Utility will be required to submit a separate request with the CPUC in the future for recovery of those costs. The Utility may be unable to fully recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years to collect.

If PG&E Corporation or the Utility were to be found liable for certain or all of the costs, expenses, and other losses described above with respect to the 2018 Camp fire and 2017 Northern California wildfires, the amount of such liability could exceed $30 billion, which amount does not include potential punitive damages, fines and penalties or damages related to future claims. In certain circumstances, PG&E Corporation's and the Utility's liability could be substantially greater than such amount. For further 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 2017 Northern California wildfires, notwithstanding the commencement of the Chapter 11 Cases" and "PG&E Corporation and the Utility are the subject of lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions in connection with the 2018 Camp fire and 2017 Northern California wildfires" above.

Accordingly, PG&E Corporation and the Utility expect losses in connection with the 2018 Camp fire and 2017 Northern California wildfires will greatly exceed their available insurance. 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. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability of the Utility in connection with the 2015 Butte fire.

PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the 2015 Butte fire. As described below in Note 13 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 2015 Butte fire by various plaintiffs, including individual plaintiffs, insurance carriers, and various government entities, under multiple theories of liability. Plaintiffs also seek punitive damages. The number of individual claimants may still increase in the future through the Chapter 11 process.

In connection with the 2015 Butte fire, the Utility may be liable for property damages, interest, and attorneys’ fees without having been found negligent, through the doctrine of inverse condemnation. (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, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. PG&E Corporation’s and the Utility’s obligations with respect to such claims are expected to be determined through the Chapter 11 process. While the Utility believes it was not negligent, there can be no assurance that a court would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of $1.1 billion in connection with the 2015 Butte fire. While this amount includes the Utility’s assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for that additional claim. A change in management’s estimates or assumptions could result in an adjustment that could have a material effect on 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. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

If the Utility is unable to recover all or a significant portion of its excess costs in connection with the 2018 Camp fire and 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, 2018, the Utility incurred substantial costs in connection with the 2018 Camp fire and 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, CEMA and FHPMA accounts.

There can be no assurance that the Utility will be allowed to recover 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. For example, while the CPUC previously approved WEMA tracking accounts for San Diego Gas & Electric Company in 2010, 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. San Diego Gas & Electric, the Utility, and Southern California Edison filed requests for rehearing of that decision. On July 12, 2018, the CPUC voted out a decision denying the requests for rehearing. On November 13, 2018, the California Court of Appeal denied San Diego Gas & Electric's petition for writ of review, and on January 30, 2019, the California Supreme Court denied San Diego Gas & Electric's petition for review.

SB 901, signed into law on September 21, 2018, requires the CPUC to establish a customer harm threshold, 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 (the "Customer Harm Threshold"). 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 Customer Harm Threshold. 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.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Based on the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs, and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Based on the OIR, as well as prior experience and precedent, and unless the CPUC alters the position expressed in the OIR, PG&E Corporation and the Utility believe it likely would take years to obtain authorization to securitize any amounts relating to the 2017 Northern California wildfires.

On February 11, 2019, PG&E Corporation and the Utility filed opening comments in response to the OIR in which they argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt PG&E Corporation and the Utility can raise. Based on assumptions set forth in the comments, PG&E Corporation and the Utility indicated that they could borrow up to approximately $3 billion to fund wildfire claims costs as part of a plan of reorganization.

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 non-compliance with the terms of probation or in the event of 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 non-compliance with the terms of probation or in the event of 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. On November 27, 2018, the court issued an order requiring that the Utility, the United States Attorney's Office for the Northern District of California and the third-party monitor provide written answers to a series of questions regarding the Utility's compliance with the terms of its probation. 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 response of the Utility was submitted on December 31, 2018. On January 3, 2019 and January 4, 2019, the court issued two new orders requesting further information regarding each of the eighteen October 2017 Northern California wildfires that Cal Fire has attributed to the Utility's facilities, and the Utility submitted its responses 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 proposing to add new conditions of probation and ordered the Utility 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. 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. For more information about the Utility's probation and the court's orders, see "U.S. District Court Matters and Probation" in Item 3. Legal Proceedings and "U.S. District Court Matters and Probation" in Note 15 of the Notes to Consolidated Financial Statements in Item 8. 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 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 modifications to the conditions of its probation.

The Utility's conviction and 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, they could negatively affect the outcome of future ratemaking and regulatory proceedings, for example, by enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was found guilty. They could also result in increased regulatory or legislative scrutiny 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 and 2017 Northern California wildfires and the 2015 Butte fire, and it is possible that plaintiffs could be successful in convincing courts to apply this doctrine in these or other litigations. For example, on June 22, 2017, the Superior Court for the County of Sacramento found that the doctrine of inverse condemnation applies to the Utility with respect to the 2015 Butte fire. Although the Utility has filed a renewed motion for a legal determination of inverse condemnation liability, there can be no assurance that the Utility will be successful in its arguments that the doctrine of inverse condemnation does not apply in 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 is premised on the assumption that utilities have the ability to automatically recover these costs from their customers, there can be no guarantee that the CPUC would authorize cost recovery whether or not a previous court decision imposes 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 is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison.

If PG&E Corporation or the Utility were to be found liable for damage under the doctrine of inverse condemnation, but is 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 2018 Camp fire and 2017 Northern California wildfires. (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 2017 Northern California wildfires, notwithstanding the commencement of the Chapter 11 Cases", "PG&E Corporation and the Utility are the subject of lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions in connection with the 2018 Camp fire and 2017 Northern California wildfires" and "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability of the Utility in connection with the 2015 Butte fire" above.)

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. Following SB 901, in applications for cost recovery in connection with the 2017 wildfires, the CPUC is expected to consider the Utility's financial status and determine the maximum amount the Utility can pay without harming customers or materially impacting its ability to provide adequate and safe service, and ensure that the costs or expenses that are disallowed for recovery in rates assessed for the wildfires, in the aggregate, do not exceed that amount. The Utility is unable to predict the timing or outcome of such future determination by the CPUC and its impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

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.  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. (See "Regulatory Matters - Other Regulatory Proceedings" in Item 7. MD&A.)

Finally, SB 901 established a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures. The recommendations of the CPUC and the response by the Governor and legislature to those recommendations could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "Regulatory Matters - Legislative and Regulatory Initiatives" in Item 7. MD&A.)

The Utility is subject to extensive regulations and the risk of enforcement proceedings in connection 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 could incur material costs and fines in connection with compliance with penalties from closed investigations or enforcement actions or in connection with future investigations, citations, audits, or enforcement actions.

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 such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the ex parte OII, safety culture OII, the locate and mark 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 is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. For offenses occurred after January 1, 2019, the maximum statutory penalty is $100,000, as provided in SB 901. 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. While it is uncertain how the CPUC will 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 14 to the Consolidated Financial Statements in Item 8.)

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.) In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility also is unable to predict the outcome of, or costs and expenses associate with, pending investigations, including whether any charges will be brought against the Utility.

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.)

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.

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, the increasing amount of Reliability Must Run (“RMR”) electric generation in the CAISO 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 time lag 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 whether the associated ratemaking mechanisms can be timely adjusted to reflect a lower 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 who 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, that can cause explosions, fires, 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 wild land fire 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;
- 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.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or 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 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 wildfire 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 the ongoing drought, 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 industry is undergoing significant change 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.

The industry change, 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 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 the 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 plant ceases 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, 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. In its January 11, 2018 decision, the CPUC authorized rate recovery up to $211.3 million and in its November 29, 2018 decision, the CPUC authorized rate recovery up to $352.1 million as originally requested by the Utility for an employee retention program, but there can be no assurance that the Utility will be successful in retaining highly skilled personnel under such program.

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, 2018, the Utility’s unrecovered investment in Diablo Canyon was $1.7 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 2: 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 (recently acquired 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.

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, 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 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 an 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 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 14 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 14 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. 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.

Other Risk Factors

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.



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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.

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 2: 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, 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 8 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 160,000, acres of land, including approximately 131,000 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 70,000 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 13, 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 issued a judgment of conviction against the Utility. The court sentenced the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

The 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.

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 third-party 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 third-party 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 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 Safety 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. As of February 24, 2019, to the Utility's knowledge, no parties have submitted comments to the court on the 2019 Wildfire Safety Plan.

Order Instituting an Investigation into 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 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 the PD in connection with this proceeding. The decision 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 a Scoping Memo and Ruling (the "Scoping Memo") setting forth the scope to be addressed in the next phase of its ongoing investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately directs resources to promote accountability and achieve safety goals and standards (the "Safety Culture OII"). The Scoping Memo provides 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."

In the Scoping Memo, the CPUC alleges that the Utility has had "serious safety problems with both its gas and electric operations for many years" and 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 outlines 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 does not propose penalties and states 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. Reply comments are due on February 28, 2019.

PG&E Corporation and the Utility are unable to predict whether additional fines, penalties, or other ratemaking tools such as a potential reduction of the Utility's return on equity will be adopted by the CPUC in future phases of this proceeding.

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 Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement was that the Central Coast Board renew Diablo Canyon's permit.

However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists to develop additional information on possible mitigation measures for Central Coast Board staff. In 2005, the Central Coast Board reviewed the scientists' draft report recommending several such mitigation measures, but no action was taken.

In 2010, the California Water Board adopted a policy on once-through cooling that 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 January 11, 2018, the CPUC approved the retirement of Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. 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, starting in 2017, the Utility pays an annual interim mitigation fee, which it will continue to pay 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 and the Central Coast 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 [1] of PG&E Corporation and/or the Utility, as of February 28, 2019. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| John R. Simon | 54 | Interim Chief Executive Officer, PG&E Corporation | January 13, 2019 to present |
| | | Executive Vice President and General Counsel, PG&E Corporation | March 1, 2017 to January 13, 2019 |
| | | Executive Vice President, Corporate Services and Human Resources, PG&E Corporation | August 17, 2015 to February 28, 2017 |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | April 16, 2007 to August 16, 2015 |
| Jason P. Wells | 41 | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to present |
| | | Vice President, Business Finance | August 1, 2013 to December 31, 2015 |
| Loraine M. Giammona | 52 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| Julie M. Kane | 60 | Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel, PG&E Corporation and Pacific Gas and Electric Company | March 21, 2017 to present |
| | | Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company | May 18, 2015 to March 20, 2017 |
| | | Vice President, General Counsel and Compliance Officer, North America, Avon Products, Inc. | September 30, 2013 to March 31, 2015 |
| | | Vice President, Ethics and Compliance, Novartis Corporation | January 1, 2010 to August 31, 2015 |
| Kathleen B. Kay | 56 | Senior Vice President and Chief Information Officer | September 1, 2018 to present |
| | | Vice President, Business Technology | September 1, 2015 to August 31, 2018 |
| | | Senior Vice President, Application Services, SunTrust Bank, Inc. | September 2012 to May 2015 |
| Michael A. Lewis | 56 | 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 |
| | | Senior Vice President, Energy Delivery, Progress Energy Florida | January 2008 to December 2014 |

| | | | |
|---|---|---|---|
| Janet C. Loduca | 51 | Senior Vice President and Interim General Counsel, PG&E Corporation and Pacific Gas and Electric Company | January 13, 2019 to present |
| | | 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 |
| | | Vice President, Safety, Health, and Environment | April 23, 2014 to December 31, 2014 |
| | | Vice President, Environmental | October 1, 2011 to April 22, 2014 |
| Steven E. Malnight | 46 | Senior Vice President, Energy Supply and Policy | September 1, 2018 to present |
| | | Senior Vice President, Strategy and Policy, PG&E Corporation and Pacific Gas and Electric Company | March 1, 2017 to August 31, 2018 |
| | | Senior Vice President, Regulatory Affairs | September 18, 2014 to February 28, 2017 |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| Dinyar B. Mistry | 57 | Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company | February 1, 2017 to present |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | June 1, 2016 to January 31, 2017 |
| | | Senior Vice President, Human Resources, Chief Financial Officer, and Controller | March 1, 2016 to May 31, 2016 |
| | | Senior Vice President, Human Resources and Controller, PG&E Corporation | March 1, 2016 to May 31, 2016 |
| | | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to February 28, 2016 |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to February 28, 2016 |
| Jesus Soto, Jr. | 51 | Senior Vice President, Gas Operations | September 8, 2015 to present |
| | | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to September 8, 2015 |
| Fong Wan | 57 | Senior Vice President, Energy Policy and Procurement, Pacific Gas and Electric Company | September 8, 2015 to present |
| | | Senior Vice President, Energy Procurement | October 1, 2008 to September 8, 2015 |
| David S. Thomason | 43 | 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 |
| | | Senior Director, Financial Forecasting and Analysis | September 1, 2012 to March 1, 2014 |

[1] Mr. Simon, Mr. Wells, Ms. Kane, Mr. Lewis, Ms. Loduca, Mr. Malnight, Mr. Mistry, and Mr. Soto are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.

PART II

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

As of February 22, 2019, there were 49,939 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. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock appears 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 in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

Sales of Unregistered Equity Securities

PG&E Corporation made equity contributions to the Utility totaling $45 million during the quarter ended December 31, 2018. PG&E Corporation did not make any sales of unregistered equity securities during 2018 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, 2018, 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, 2018, 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) | 2018 | 2017 | 2016 | 2015 | 2014 |
|---|---|---|---|---|---|
| PG&E Corporation | | | | | |
| For the Year | | | | | |
| Operating revenues | $16,759 | $17,135 | $17,666 | $16,833 | $17,090 |
| Operating income (loss) | (9,700) | 2,956 | 2,177 | 1,508 | 2,450 |
| Net income (loss) | (6,837) | 1,660 | 1,407 | 888 | 1,450 |
| Net earnings (loss) per common share, basic [1] | (13.25) | 3.21 | 2.79 | 1.81 | 3.07 |
| Net earnings (loss) per common share, diluted | (13.25) | 3.21 | 2.78 | 1.79 | 3.06 |
| Dividends declared per common share [2] | — | 1.55 | 1.93 | 1.82 | 1.82 |
| At Year-End | | | | | |
| Common stock price per share | $23.75 | $44.83 | $60.77 | $53.19 | $53.24 |
| Total assets [3] | 76,995 | 68,012 | 68,598 | 63,234 | 60,228 |
| Long-term debt (excluding current portion) | — | 17,753 | 16,220 | 15,925 | 15,151 |
| Capital lease obligations (excluding current portion) [3] | 9 | 18 | 31 | 49 | 69 |
| Pacific Gas and Electric Company | | | | | |
| For the Year | | | | | |
| Operating revenues | $16,760 | $17,138 | $17,667 | $16,833 | $17,088 |
| Operating income (loss) | (9,699) | 2,900 | 2,181 | 1,511 | 2,452 |
| Income (loss) available for common stock | (6,832) | 1,677 | 1,388 | 848 | 1,419 |
| At Year-End | | | | | |
| Total assets | 76,471 | 67,884 | 68,374 | 63,037 | 59,964 |
| Long-term debt (excluding current portion) | — | 17,403 | 15,872 | 15,577 | 14,799 |
| Capital lease obligations (excluding current portion) [3] | 9 | 18 | 31 | 49 | 69 |

[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 5 of the Notes to the Consolidated Financial Statements in Item 8.
[3] The capital 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 the Utility, 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 and by the FERC in its TO rate cases 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). 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).

PG&E Corporation and the Utility continue to operate their businesses as debtors 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. As debtors in possession, PG&E Corporation and the Utility are authorized to continue to operate as ongoing businesses, and may pay all debts and honor all obligations arising in the ordinary course of their businesses after the Petition Date. However, PG&E Corporation and the Utility may not pay third-party claims or creditors on account of obligations arising before the Petition Date or engage in transactions outside the ordinary course of business without approval 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 under Note 13 of the Notes to the Consolidated Financial Statements in Item 8), are subject to an automatic stay. Absent an order of the Bankruptcy Court providing otherwise, substantially all pre-petition liabilities will be administered under a Chapter 11 plan of reorganization to be voted upon by creditors and other stakeholders, and approved by the Bankruptcy Court. However, under the Bankruptcy Code, regulatory or criminal proceedings are generally not subject to an automatic stay, and PG&E Corporation and the Utility expect these proceedings to continue during the pendency of the Chapter 11 Cases.

To assure ordinary course operations, on January 31, 2019, PG&E Corporation and the Utility received interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions that authorize them to maintain their existing cash management system, to continue wage and salary payments and other benefits to their employees, to secure debtor in possession financing and other customary relief. On February 27, 2019, PG&E Corporation and the Utility received final approval of the first day motion to continue wage and salary payments and other benefits to their employees (with one limited objection with respect to a discrete matter having been preserved by the Bankruptcy Court) and certain other first day motions for customary relief. Hearings on certain other first day motions, including a hearing to consider final approval of PG&E Corporation’s and the Utility’s motions to continue their existing cash management system and to approve their debtor in possession financing, have not been held and no assurances can be given that the Bankruptcy Court will approve such motions on a final basis. PG&E Corporation and the Utility are unable to predict the date of the final hearing with respect to such motions, but there are hearings currently scheduled for March 12, March 13 and March 27, 2019.

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 DIP Lenders. The DIP Credit Agreement provides for $5.5 billion in the form of (i) the DIP Revolving Facility in an aggregate amount of $3.5 billion, including a $1.5 billion letter of credit subfacility, (ii) the DIP Initial Term Loan Facility in an aggregate principal amount of $1.5 billion and (iii) the DIP Delayed Draw Term Loan Facility in an aggregate principal amount of $500 million, subject to the terms and conditions set forth therein. As a result of the Bankruptcy Court’s interim approval of the DIP Credit Agreement on January 31, 2019, 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 PG&E Corporation and the Utility. As of February 28, 2019, 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 are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all.

Borrowings under the DIP Credit Agreement 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 Credit Agreement 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 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. The Utility paid customary fees and expenses in connection with obtaining the DIP Credit Agreement.

The commencement of the Chapter 11 Cases constituted an event of default or termination event, 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”). 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 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 4 of the Notes to the Consolidated Financial Statements in Item 8. The filing of the Chapter 11 Cases may also provide the counterparties under certain commodity and related agreements with the right to declare an event of default and to seek termination of such agreements, with such rights subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. (For more information, see "Liquidity and Financial Resources - Financial Resources - Acceleration of Pre-petition Debt Obligations" in Item 7. MD&A.)

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.

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 PG&E Corporation’s and the Utility’s relationships with suppliers and employees which, in turn, could adversely affect the value of PG&E Corporation’s and the Utility’s business and assets. At this time, it is not possible to predict with certainty the impact of the Chapter 11 Cases on PG&E Corporation’s and the Utility’s 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 results depend upon the confirmation, and successful implementation, on a timely basis, of a Chapter 11 plan of reorganization. For a discussion of the significant risks and uncertainties related to the Chapter 11 Cases, see “Risks Related to Chapter 11 Proceedings and Liquidity” in Item 1A. Risk Factors.

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 are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. 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 Item 3. Legal Proceedings, Item 7. MD&A, and Note 15 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' 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. 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 Note 1 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 losses available for common shareholders were $6.9 billion in 2018, compared to net income available for common shareholders of $1.6 billion in 2017. In 2018, PG&E Corporation recognized charges of $14 billion (pre-tax), offset by probable insurance recoveries of $2.2 billion (pre-tax), associated with third-party claims and legal and other costs related to the 2018 Camp fire and 2017 Northern California wildfires.

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 expect 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.

- 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, 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. The remainder of the DIP Facilities are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. 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, cash flow from operations and distributions received from subsidiaries, 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, 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 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 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 (in 2018, the Utility recorded total charges of $13.4 billion, which reflects the low end of the range of reasonably estimated losses and is subject to change based on additional information), which aggregate possible losses, if the Utility were found liable for certain or all of the costs, expenses and other losses in connection with the 2018 Camp fire and 2017 Northern California wildfires (other than potential punitive damages, fines and penalties or damages related to future claims), could exceed $30 billion; punitive damages, which could be material; fines or penalties, which could be material, if the CPUC or any law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations; the amount of 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, which the Utility intends to continue to challenge during the pendency of its Chapter 11 Case; 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 amount of the Customer Harm Threshold under SB 901 and the timing of any recovery by the Utility in excess of the Customer Harm Threshold in a proceeding before the CPUC; and recoverability of clean-up and repair costs (the Utility incurred costs of $681 million for clean-up and repair of the Utility's facilities through December 31, 2018). (See Notes 3 and 13 of the Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.)

- The Outcome of Other Enforcement, Litigation, and Regulatory Matters. 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 the outcome of the Locate and Mark OII, phase two of the Safety Culture OII, the outcome of phase two of the ex parte 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 third-party monitor, and potential penalties in connection with the Utility's safety and other self-reports. (See Notes 13 and 14 of the Notes to the Consolidated Financial Statements in Item 8.)

- The Timing and Outcome of Ratemaking Proceedings. The Utility's financial results may be impacted by the timing and outcome of its 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19, and TO20 rate cases, future cost of capital proceedings, and its ability to timely recover costs not in rates already incurred and to be incurred in the future, including those tracked in its CEMA, WEMA, FHPMA and the Utility's 2019 Wildfire Safety Plan. 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 3 and 14 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. 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 intends to submit 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 unable to predict the timing and outcome of its waiver application.

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 the 2018 Form 10-K. In addition, this 2018 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 2018, 2017, and 2016. 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) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Consolidated Total | $(6,851) | $1,646 | $1,393 |
| PG&E Corporation | (19) | (31) | 5 |
| Utility | $(6,832) | $1,677 | $1,388 |

PG&E Corporation's net income (loss) primarily consists of income taxes and interest expense on long-term debt and other income from investments. The decrease in PG&E Corporation's net loss for 2018, as compared to 2017, is 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.

PG&E Corporation's net income decreased in 2017, as compared to 2016, primarily due to the impact of the Tax Act and interest expense, partially offset by the impact of the San Bruno Derivative Litigation.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2018, 2017, and 2016. 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.

| | 2018 Revenues and Costs: | | | 2017 Revenues and Costs: | | | 2016 Revenues and Costs: | | |
|---|---|---|---|---|---|---|---|---|---|
| (in millions) | 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 | $7,859 | $4,854 | $12,713 | $7,897 | $5,230 | $13,127 | 7,955 | 5,910 | 13,865 |
| Natural gas operating revenues | 3,046 | 1,001 | 4,047 | 2,969 | 1,042 | 4,011 | 2,767 | 1,035 | 3,802 |
| Total operating revenues | 10,905 | 5,855 | 16,760 | 10,866 | 6,272 | 17,138 | 10,722 | 6,945 | 17,667 |
| Cost of electricity | — | 3,828 | 3,828 | — | 4,309 | 4,309 | — | 4,765 | 4,765 |
| Cost of natural gas | — | 671 | 671 | — | 746 | 746 | — | 615 | 615 |
| Operating and maintenance | 5,475 | 1,678 | 7,153 | 5,112 | 1,271 | 6,383 | 5,662 | 1,665 | 7,327 |
| Wildfire-related claims, net of insurance recoveries | 11,771 | — | 11,771 | — | — | — | 125 | — | 125 |
| Depreciation, amortization, and decommissioning | 3,036 | — | 3,036 | 2,854 | — | 2,854 | 2,754 | — | 2,754 |
| Total operating expenses | 20,282 | 6,177 | 26,459 | 7,966 | 6,326 | 14,292 | 8,541 | 7,045 | 15,586 |
| Operating income (loss) | (9,377 ) | (322 ) | (9,699 ) | 2,900 | (54 ) | 2,846 | 2,181 | (100 ) | 2,081 |
| Interest income | 74 | — | 74 | 30 | — | 30 | 22 | — | 22 |
| Interest expense | (914 ) | — | (914 ) | (877 ) | — | (877 ) | (819 ) | — | (819 ) |
| Other income, net | 104 | 322 | 426 | 65 | 54 | 119 | 88 | 100 | 188 |
| Income (loss) before income taxes | (10,113) | — | (10,113 ) | 2,118 | — | 2,118 | 1,472 | — | 1,472 |
| Income tax provision (benefit) [1] | | | (3,295 ) | | | 427 | | | 70 |
| Net income (loss) | | | (6,818 ) | | | 1,691 | | | 1,402 |
| Preferred stock dividend requirement [1] | | | 14 | | | 14 | | | 14 |
| Income (Loss) Available for Common Stock | | | $(6,832 ) | | | $1,677 | | | $1,388 |

[1] These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2018, 2017, and 2016, 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 $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. See "Regulatory Matters" below.

The Utility’s electric and natural gas operating revenues that impacted earnings increased $144 million, or 1%, in 2017 compared to 2016, primarily due to higher electric transmission revenues.



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Operating and Maintenance

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).

The Utility’s operating and maintenance expenses that impacted earnings decreased $550 million, or 10%, in 2017 compared to 2016. In 2017, the Utility incurred $455 million less in disallowed charges (the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement in 2017 as compared to $502 million of disallowed capital charges related to the San Bruno Penalty Decision and 2015 GT&S rate case decision in 2016). This decrease was partially offset by a $64 million write off of insurance premiums for single event coverage policies recorded in 2017, with no corresponding activity in 2016. Additionally, the decrease was offset by a $51 million increase in legal and other costs (the Utility recorded $18 million relating to the 2017 Northern California wildfires and $60 million relating to the 2015 Butte fire in 2017, as compared to $27 million relating to the 2015 Butte fire in 2016).

Wildfire-related claims, net of insurance recoveries

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.

In 2016, the Utility recognized a $750 million charge, offset by probable insurance recoveries of $625 million related to the 2015 Butte fire.

Depreciation, Amortization, and Decommissioning

The Utility’s depreciation, amortization, and decommissioning expenses increased by $182 million, or 6%, in 2018 compared to 2017, primarily due to capital additions. In 2017, the Utility's depreciation, amortization, and decommissioning expenses increased by $100 million, or 4%, compared to 2016, primarily due to the impact of capital additions and higher depreciation rates as authorized by the CPUC in the 2017 GRC.

Interest Income

The Utility's interest income increased by $44 million, or 147%, in 2018 as compared to 2017, primarily due to higher interest rates affecting various regulatory balancing accounts and fluctuations in those accounts. There was no material change in the Utility's interest income in 2017 as compared to 2016. 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 increased by $37 million, or 4%, in 2018 compared to 2017. The Utility's interest expenses increased by $58 million, or 7%, in 2017 compared to 2016, primarily due to the issuance of additional long-term debt.

Other Income, Net

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. There was no material change in the Utility's other income, net in 2017 as compared to 2016.

Income Tax Provision

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 Utility's income tax provision increased $357 million in 2017 compared to 2016. The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 2017 compared to 2016 and an adjustment required to record the change in deferred tax balances due to tax reform in 2017 with no comparable adjustment in 2016.

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

| | 2018 | 2017 | 2016 |
|---|---|---|---|
| Federal statutory income tax rate | 21.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) [1] | 7.9 % | 1.6 % | (2.2 )% |
| Effect of regulatory treatment of fixed asset differences [2] | 3.6 % | (16.8)% | (23.4)% |
| Tax credits | 0.1 % | (1.1 )% | (0.8 )% |
| Benefit of loss carryback | — % | — % | (1.1 )% |
| Compensation Related [3] | (0.1 )% | (0.9 )% | (0.2 )% |
| Tax Reform Adjustment [4] | 0.1 % | 3.0 % | — % |
| Other, net [5] | — % | (0.7 )% | (2.5 )% |
| Effective tax rate | 32.6 % | 20.1 % | 4.8 % |

[1] Includes the effect of state flow-through ratemaking treatment. In 2016, amounts reflect a settlement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
[2] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision (impacting the twelve months ended December 31, 2017), the 2017 GRC decision (impacting the twelve months ended December 31, 2018), and by the 2015 GT&S decision which impacted all periods presented. All amounts are impacted by the level of income before income taxes. The 2014 GRC, 2017 GRC, and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 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 tax audit settlements.

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.

63

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. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's total purchased power is driven by customer demand, 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) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Cost of purchased power | $3,531 | $4,039 | $4,510 |
| Fuel used in own generation facilities | 297 | 270 | 255 |
| Total cost of electricity | $3,828 | $4,309 | $4,765 |
| Average cost of purchased power per kWh (1) | $0.168 | $0.140 | $0.109 |
| Total purchased power (in millions of kWh) (2) | 21,024 | 28,750 | 41,324 |

(1) Average cost of purchased power was impacted primarily by lower Utility electric customer demand, driven by customer departures to CCAs or direct access providers, and a larger percentage of higher cost renewable energy resources being allocated to the fewer remaining Utility electric customers. See further discussion in "Legislative and Regulatory Initiatives - Power Charge Indifference Adjustment," below.
(2) The decrease in purchased power for 2018 compared to 2017 was primarily due to lower Utility electric customer demand.

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 9 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) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Cost of natural gas sold | $561 | $627 | $481 |
| Transportation cost of natural gas sold | 110 | 119 | 134 |
| Total cost of natural gas | $671 | $746 | $615 |
| Average cost per Mcf (1) of natural gas sold | $2.70 | $2.97 | $2.45 |
| Total natural gas sold (in millions of Mcf) | 208 | 211 | 196 |

(1) One thousand cubic feet

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 2018, 2017, and 2016, 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.

64

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 a DIP Credit Agreement. 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. On January 31, 2019, the Bankruptcy Court provided interim approval of the DIP Facilities and on February 1, 2019, the DIP Credit Agreement was executed and became effective 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 PG&E Corporation and the Utility. As of February 28, 2019, 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 are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all. (For more information on the DIP Credit Agreement, see "DIP Credit Agreement" below and Note 4 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. Effective February 5, 2019, Moody's has withdrawn each of its 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 additional collateral under its commodity purchase agreements, and other obligations, and has been exposed to significant constraints on its customary trade credit. 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 9 and 14 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.

As of December 31, 2018, PG&E Corporation and the Utility had unconsolidated cash and cash equivalent balances of $373 million and $1.3 billion, respectively. On the Petition Date, PG&E Corporation and the Utility had unconsolidated cash and cash equivalent balances of $370 million and $490 million (including approximately $250 million of customer deposits and cash held from counterparties by the Utility), respectively. Starting in early January 2019, the Utility's cash and cash equivalent balance decreased by approximately $811 million to satisfy collateral posting needs, address accelerated payment and pre-pay demands of energy commodity suppliers, and to address requests from other essential suppliers for shortened payment terms or elimination of credit lines. As of February 27, 2019, PG&E Corporation and the Utility had unconsolidated cash and cash equivalent balances of approximately $480 million and $1.7 billion, respectively.

Financial Resources

Acceleration of Pre-petition Debt Obligations

The commencement of the Chapter 11 Cases constituted an event of default or termination event, 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 all 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 4 of the Notes to the Consolidated Financial Statements in Item 8.

DIP Credit Agreement

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement. As a result of the Bankruptcy Court’s interim approval of the DIP Credit Agreement on January 31, 2019, 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 PG&E Corporation and the Utility. As of February 28, 2019, 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 are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all.

Borrowings under the DIP Credit Agreement 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 Credit Agreement 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 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. The Utility paid customary fees and expenses in connection with obtaining the DIP Credit Agreement. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for a more detailed description of the DIP Credit Agreement.

As of February 28, 2019, the Utility had outstanding borrowings of $350 million under the DIP Revolving Facility, and $30 million in face amount of outstanding letters of credit, with remaining availability of $1.12 billion under the DIP Revolving Facility.

CPUC Authorization of DIP Credit Agreement

On January 28, 2019, the CPUC granted the Utility exemptions from the requirement of prior CPUC approval for issuance of debt instruments for the incurrence of the DIP financing. The CPUC also indicated its position that the exemptions do not extend to the transfer of ownership of any Utility asset that is pledged as part of the DIP financing and that in the event of the Utility’s default under the DIP financing, the Utility would need to seek the CPUC’s approval to execute such a transfer. Further, the CPUC indicated that the Utility's "expenditure of the initial DIP financing funds for any purposes may not be recovered from ratepayers without Commission approval in a future application for rate recovery" and that the Utility "bears the burden of demonstrating the reasonableness of any expenditure."

66

Pre-petition Debt and Equity Financings

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the twelve months ended December 31, 2018.

During 2018, PG&E Corporation issued 5.6 million shares of common stock for cash proceeds of $199 million under the PG&E Corporation 401(k) plan and share-based compensation plans. The proceeds from these sales were used for general corporate purposes. Beginning January 1, 2019, PG&E Corporation's matching contributions under its 401(k) plan are deposited in cash.

During the first quarter of 2018, the Utility satisfied and discharged its remaining obligation of $400 million aggregate principal amount of the 8.25% Senior Notes due October 15, 2018.

In February 2018, the Utility’s $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. In February 2018, the Utility entered into a new $250 million floating rate unsecured term loan. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility’s outstanding commercial paper. As a result of the Chapter 11 Cases, the Utility's obligation to repay this loan, which was scheduled to mature on February 22, 2019, has been stayed.

In April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. The term loan was scheduled to mature on April 16, 2020. As a result of the Chapter 11 Cases, PG&E Corporation's obligation to repay this loan has been stayed. The proceeds were used for general corporate purposes, including the early redemption of PG&E Corporation’s outstanding $350 million principal amount of 2.40% Senior Notes due March 1, 2019. On April 26, 2018, PG&E Corporation completed the early redemption of these bonds, which satisfied and discharged its remaining obligation of $350 million.

In August 2018, the Utility issued $500 million principal amount of 4.25% senior notes due August 1, 2023 and $300 million principal amount of 4.65% senior notes due August 1, 2028. The proceeds were used to repay $500 million floating rate Senior Notes due November 28, 2018 and for general corporate purposes.

In November 2018, the Utility’s $500 million floating rate unsecured term loan, issued in November 2017, matured and was repaid.

In December 2018, the Utility’s $45 million principal amount of 1.05% Series 2008 G pollution control bonds matured and were repaid.

In November 2018, PG&E Corporation and the Utility drew all amounts available under their respective revolving credit facilities in the amount of $300 million and $2.85 billion, respectively. At December 31, 2018, PG&E Corporation and the Utility had aggregate borrowings outstanding under their respective revolving credit facilities of $300 million and $2.965 billion, respectively. The Utility’s aggregate borrowings under its revolving credit facility includes $2.85 billion of revolving credit loans, and approximately $80 million of letters of credit outstanding. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

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 the 2017 Northern California wildfires. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

67

Utility Cash Flows

The Utility's cash flows were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 2018 | 2017 | 2016 |
| Net cash provided by operating activities | $4,704 | $5,916 | $4,344 |
| Net cash used in investing activities | (6,564 ) | (5,650 ) | (5,753 ) |
| Net cash provided by financing activities | 2,708 | 110 | 1,194 |
| Net change in cash and cash equivalents | $848 | $376 | $(215 ) |

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 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.

During 2017, net cash provided by operating activities increased by $1.6 billion compared to 2016. This increase was primarily due to additional electric and natural gas operating revenues collected as authorized by the CPUC in the 2015 GT&S rate case, the $400 million refund to natural gas customers in the second quarter of 2016, as required by the San Bruno Penalty Decision (with no corresponding activity in 2017), and the receipt of approximately $300 million of insurance recoveries related to the 2015 Butte fire in 2017 as compared to $50 million of insurance recoveries related to the 2015 Butte fire during 2016.

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 13 and "Enforcement and Litigation Matters" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8. and Item 3. Legal Proceedings for more information);

- the timing and amount of premium payments related to wildfire insurance (see "Wildfire Insurance" in Note 14 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 (see Note 8 of the Notes to the Consolidated Financial Statements in Item 8 and "Regulatory Matters" below for more information);

- the timing and outcomes of the 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19 and TO20 rate cases, 2018 CEMA filing, 2020 Cost of Capital, NDCTP, and other ratemaking and regulatory proceedings; and

- the timing and amount of substantially increasing costs in connection with the 2019 Wildfire Safety Plan (see "Overview" above and "Regulatory Matters" below for more information).

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 increased by $914 million during 2018 as compared to 2017 primarily due to an increase of approximately $873 million in capital expenditures. Net cash used in investing activities increased by $124 million during 2017 as compared to 2016 primarily due to an increase 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 $7.1 billion in capital expenditures in 2019, and $6.9 billion in 2020.

Financing Activities

During 2018, net cash provided by financing activities increased by $2.6 billion as compared to 2017. This increase was primarily due to borrowings under revolving credit facilities.

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. The Utility generally utilizes long-term debt issuances, retained earnings, and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2018:

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| (in millions) | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
| Utility | | | | | |
| Long-term debt [(1)] | $813 | $3,709 | $3,190 | $24,172 | $31,884 |
| Purchase obligations [(2)] | | | | | |
| Power purchase agreements | 2,971 | 5,726 | 4,754 | 24,814 | 38,265 |
| Natural gas supply, transportation, and storage | 412 | 246 | 186 | 264 | 1,108 |
| Nuclear fuel agreements | 108 | 215 | 103 | 47 | 473 |
| Pension and other benefits [(3)] | 351 | 684 | 684 | 342 | 2,061 |
| Operating leases [(2)] | 44 | 77 | 47 | 121 | 289 |
| Preferred dividends [(4)] | 14 | 28 | 28 | — | 70 |
| PG&E Corporation | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Long-term debt [1] | 12 | 355 | — | — | 367 |
| Total Contractual Commitments | $4,725 | $11,040 | $8,992 | $49,760 | $74,517 |

[1] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2018 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 4 of the Notes to the Consolidated Financial Statements in Item 8.
[2] See "Purchase Commitments" and "Other Commitments" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.
[3] See Note 11 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 6 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 8 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.

As of the date of this Annual Report on Form 10-K, PG&E Corporation and the Utility continue to evaluate if they will seek to assume or reject any power purchase agreement in connection with the Chapter 11 Cases. Any decision to assume or reject any power purchase agreement will be made by PG&E Corporation’s and the Utility’s management in consideration of then-existing economic, regulatory, market and legal conditions and other relevant considerations, subject to the Bankruptcy Court and potentially other approvals.

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 14 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 13 and 14 of the Notes to the Consolidated Financial Statements in Item 8. and Legal Proceedings in Item 3. 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.

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.

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. The PFM, if adopted, would 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. The Utility cannot predict the timing and outcome of this PFM.

The Utility provided an update of the cost effectiveness study for the SmartMeter™ Upgrade project to the CPUC on July 10, 2017. On January 31, 2019, the CPUC extended the statutory deadline for the 2017 GRC to August 9, 2019, in order to allow for comments and CPUC action on any PD on the SmartMeter™ upgrade cost effectiveness study. The Utility cannot predict the timing and outcome of any CPUC action in connection with this study and its impact on the 2017 GRC revenue requirement and rate base.

2020 General Rate Case

On December 13, 2018, the Utility filed its 2020 GRC application with the CPUC. In the 2020 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2020 through 2022 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 Utility's request also reflects an updated capital forecast for 2018 and 2019. The 2020 GRC application also includes recorded costs for 2017 and updated forecasts for the proposed mitigations for the period 2018 through 2022 for the Utility's top safety-related risks as presented in the Utility's November 2017 RAMP report.

For 2020, the Utility has requested base revenues of $9.6 billion, an increase of $1.1 billion, or 12.4%, as compared to authorized base revenues for 2019. The requested weighted average rate base for 2020 is approximately $30 billion, which corresponds to an increase of $2.7 billion over the 2019 authorized rate base of $27.3 billion. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2021 and 2022 by $454 million and $486 million, respectively. Over the 2020-2022 GRC period, the Utility plans to make average annual capital investments of approximately $4.5 billion in electric distribution, natural gas distribution and electric generation infrastructure, and to improve safety, reliability, and customer service.

The following tables compare the requested 2020 revenue requirement amounts with the comparable revenue requirements currently authorized for 2019, by both line of business and cost category:

| Line of Business:<br>(in millions) | Amounts Requested in the GRC Application | Amounts Currently Authorized for 2019 [(1)] | Increase (Decrease) to 2019 Authorized Amounts |
|---|---|---|---|
| Electric distribution | $ 5,113 | $ 4,364 | $ 749 |
| Gas distribution | 2,097 | 1,963 | 134 |
| Electric generation | 2,366 | 2,191 | 175 |
| Total revenue requirements | $ 9,576 | $ 8,518 | $ 1,058 |

| Cost Category:<br>(in millions) | | | |
|---|---|---|---|
| Operations and maintenance | $2,156 | $1,946 | $210 |
| Customer services | 319 | 338 | (19 ) |
| Administrative and general | 1,315 | 953 | 361 |
| Less: Revenue credits | (196 ) | (152 ) | (44 ) |
| Franchise fees, taxes other than income, and other adjustments | 236 | 181 | 55 |
| Depreciation (including costs of asset removal), return, income taxes, and decommissioning and amortization | 5,747 | 5,252 | 495 |
| Total revenue requirements [(2)] | $9,576 | $8,518 | $1,058 |

(1) These amounts include revenues from the Utility's 2017 GRC decision adjusted for attrition year increases, cost of capital, and reductions due to the Tax Act.
(2) These amounts may appear not to tie due to small rounding differences.

The following table summarizes the key drivers of the revenue requirement increase in 2020:

| Revenue requirement drivers | Increase to 2019 Authorized Amounts | |
|---|---|---|
| Community Wildfire Safety Program | 6.8 | % |
| Liability insurance [1] | 3.2 | % |
| Core gas and electric operations | 2.4 | % |
| Total proposed revenue requirement increase | 12.4 | % |

[1] The Utility's GRC forecast indicates that future liability insurance premium costs will be approximately $355 million in 2020

Among other things, the Utility proposes to invest a total of approximately $5 billion (including approximately $3 billion for capital expenditures) between 2018 and 2022 on CWSP measures. Through this program, the Utility proposes to bolster wildfire prevention, risk monitoring, emergency response efforts, and add new and enhanced safety measures, increase vegetation management and harden its electric system to help further reduce wildfire risks.

In addition, the Utility requests authorization to establish several new balancing accounts, including:

- a 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 costs for up to $2 billion in coverage and return to customers any overcollection if forecast costs exceed actuals costs; and

- a two-way Wildfire Safety Balancing Account to track and record actual incremental expenses and capital revenue requirements associated with the incremental costs of fire risk mitigation work that are not already addressed and recorded in another account; this would include the costs associated with overhead system hardening, enhanced vegetation management, and other incremental costs of wildfire mitigations that are approved by the CPUC in the Utility's annual wildfire mitigation plan. In accordance with SB 901, the Utility submitted its first Wildfire Safety Plan to the CPUC on February 6, 2019.

This GRC proposal does not request funding for potential lawsuits or claims resulting from the 2018 Camp fire and 2017 Northern California wildfires. Also, the Utility is not seeking recovery of compensation of PG&E Corporation’s and the Utility’s officers. In addition, the Chapter 11 Cases may impact the amount of work the Utility can commit to financing and require a change to the scope of work that the Utility proposes to accomplish in the 2020 GRC period.

In its application, the Utility requests that the CPUC issue a final decision by March 2020 and that the 2020 GRC rates be effective January 1, 2020. The prehearing conference was held February 11, 2019, to set a procedural schedule, including the dates for interested parties to submit testimony and for evidentiary hearings.

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). The Utility cannot predict the timing and outcome of this PFM.

2019 Gas Transmission and Storage Rate Case

On November 17, 2017, the Utility filed its 2019 GT&S rate case application with the CPUC for the years 2019 through 2021. The Utility also provided a revenue requirement and rates for 2022, in the event the CPUC adopts an additional year. On October 1, 2018, the Utility entered into a stipulation with PAO that, if approved, would extend the rate case cycle through 2022 as recommended by PAO.

In its application, the Utility requested that the CPUC authorize a 2019 revenue requirement of $1.59 billion to recover anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2019. This corresponds to an increase of $289 million over the Utility’s 2018 authorized revenue requirement of $1.30 billion. The Utility’s request also proposed revenue requirements of $1.73 billion for 2020, $1.91 billion for 2021, and $1.91 billion for 2022 if the CPUC orders a fourth year for the rate case period.

The Utility subsequently revised its forecast revenue requirement as a result of the Tax Act and other forecast updates, including significant reductions in the areas of gas storage facilities and gas system operations programs. The revised revenue requirements are as follows: $1.48 billion for 2019, $1.59 billion for 2020, $1.69 billion for 2021, and $1.68 billion for 2022. The revised 2019 requested revenue requirement corresponds to an increase of $184 million over the Utility's 2018 authorized revenue requirement.

The requested rate base for 2019 is $4.75 billion, which corresponds to an increase of $1.04 billion over the 2018 adopted rate base of $3.71 billion. The Utility’s request is based on capital expenditure forecasts of $829 million for 2019, $872 million for 2020, and $825 million for 2021 (which exclude common capital allocations). The requested rate base amounts 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. 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 requested increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations issued by DOGGR, the Pipeline and Hazardous Materials Safety Administration, and the CPUC.

In response to the Utility's application, parties proposed various forecast reductions. For example, the PAO recommended a 2019 revenue requirement of $1.35 billion, an increase of $45 million over 2018 adopted amounts. TURN proposed widespread reductions in forecast costs and recommended capital and expense disallowances of more than $500 million.

A later phase of the proceeding is expected to address the removal of officer compensation costs from the revenue requirement, which is required by SB 901. The Utility is unable to predict the timing and outcome of this proceeding.

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 have been remanded to FERC for further proceedings consistent with the Court of Appeals’ opinion. If FERC concludes on remand that the Utility should no longer be authorized to receive the 50 basis point ROE incentive adder, the Utility would incur a refund obligation of $1 million and $8.5 million for TO16 and TO17, respectively. Alternatively, if FERC again concludes that the Utility should receive the 50 basis point ROE incentive adder and provides 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 a hearing and 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 briefs on September 19, 2018 and reply briefs on October 10, 2018. The Utility is unable to predict the timing and outcome of FERC’s decision.

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 is seeking a return on equity of 10.9%, which includes 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 set 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.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case proposing an 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 recommendations. The Utility expects FERC to issue a decision in mid-2019, but 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 of when a final decision will be issued.

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.

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 is $6.9 billion. The Utility is seeking 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. 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, settlement judge procedures, and consolidation with the TO19 proceeding.

On September 21, 2018, the Utility filed an all-party settlement with 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 in the TO18 final decision. Additionally, if FERC determines that the Utility is not entitled to the 50 basis point incentive adder for the Utility's continued CAISO participation, than the Utility would be obligated to make a refund to customers of approximately $25 million. On December 20, 2018, FERC issued an order approving the all-party settlement.

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 Utility is unable to predict the timing and outcome of settlement discussions.

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 revenues, including CWIP, will be updated to the actual cost of service annually. 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. A settlement conference is scheduled for March 14 - 15, 2019.

The Utility expects to file an annual update to its TO tariff on or before December 1 of each year beginning in 2019, for rates and charges to become effective January 1 of the following year, consistent with the formula rate.

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 updated decommissioning cost estimate to the CPUC for Diablo Canyon based on a site-specific decommissioning analysis. A prehearing conference was held on February 6, 2019.

For more information, see "Asset Retirement Obligations" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

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 expense 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 3 and 13 of the Notes to the Consolidated Financial Statements in Item 8.)

As of December 31, 2018, the Consolidated Financial Statements include long-term regulatory assets of $94 million, consisting of insurance premium costs that are probable of recovery. 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. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC review and approval. For more information see Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

2016 CEMA Application

In 2016, the Utility submitted a request to the CPUC to authorize recovery under the CEMA tariff for a revenue requirement increase of approximately $146 million for recorded capital and expense costs related to the 2015 drought mitigations and emergency response activities for declared disasters that occurred from December 2012 through March 2016. On January 4, 2018, PAO, TURN, and the Utility filed an all-party motion with the CPUC seeking approval of an all-party settlement agreement. The settlement agreement proposed that the Utility's total CEMA revenue requirement request be reduced by $29 million, from $146 million to $117 million. On June 21, 2018, the CPUC approved the settlement agreement authorizing the Utility to recover $117 million in connection with its 2016 CEMA application.

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. Also, the 2018 CEMA application originally sought cost recovery of $555 million on a forecast basis, subject to true-up if actual costs were greater or less than the forecast, for additional tree mortality and fire risk mitigation work anticipated in 2018 and 2019. On October 12, 2018, the Utility notified the CPUC and other parties that $180 million of the forecasted 2018 and 2019 fire risk mitigation costs would be removed from CEMA and instead pursued in the FHPMA. Upon removal of the $180 million, the Utility's forecast of costs for 2018 and 2019 sought in the application would be approximately $375 million. The 2018 CEMA application does not include costs related to the 2015 Butte fire, the 2017 Northern California wildfires, or the 2018 Camp fire.

On November 2, 2018, the assigned ALJ denied the Utility's July 25, 2018 motion requesting interim rate relief for $441 million, which represents 75% of the costs incurred in 2016 and 2017 related to storms, wildfires and tree mortality response work. Subsequently, on December 4, 2018, the Utility filed a renewed motion for interim rate relief, due to worsening financial conditions. The renewed motion for interim relief sought approximately $588 million, which represents 100% of the total costs incurred in 2016 and 2017 for the activities referenced above. The Utility requested that the interim rate relief begins on March 1, 2019 and cost recovery occurs over a one-year period, with the amounts collected to be subject to refund based on the authorized amount in the proceeding.

On February 5, 2019, the assigned ALJs issued a PD on the Utility's renewed motion for interim rate relief, granting interim rate recovery “in an amount no greater than and possibly less than $373 million” of its recorded 2016 and 2017 CEMA costs, as compared to approximately $588 million requested by the Utility, subject to ensuring that the overall impact would result in no rate increase as compared to revenue at present rates. If adopted, the PD would also require the Utility to refund, with interest, any excess rate recovery amount it obtained in comparison to the final decision in this proceeding regarding the total approved 2016 and 2017 CEMA costs. Further, the PD rejected the Utility’s $555 million cost recovery request, on a forecast basis, for 2018 and 2019 anticipated costs for tree mortality and fire risk mitigation work. The PD finds, among other things, that the applicable CPUC resolution does not authorize recovery of CEMA eligible costs on a forecast basis. The Utility expects that the CPUC will vote on the PD no earlier than March 14, 2019.

PG&E Corporation and the Utility are 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 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. The Utility currently is authorized to track such costs in the FHPMA through the end of 2019. During 2018, the Utility recorded $262 million of costs to the FHPMA, corresponding to vegetation management work performed to comply with CPUC December 2017 fire safety regulations. While the Utility believes such costs are recoverable, rate recovery requires CPUC authorization in a separate proceeding or through a GRC. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

Other Regulatory Proceedings

2019 Wildfire Safety 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 will consider, among other things, how to interpret and apply SB 901’s list of required plan elements, as well as whether 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 be addressed in separate rate recovery applications.

On February 6, 2019, the Utility filed its wildfire mitigation plan with the CPUC. The 2019 Wildfire Safety Plan also 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 Safety Plan specifically addresses wildfire risk factors that occur most frequently and have potential to start or spread a fire. The new and ongoing safety measures being pursued include:

- Installing nearly 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 more reclosers and circuit breakers in high fire-threat areas with remote control capabilities
- 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 Public Safety Power Shutoff.

The CPUC is expected to issue a decision in the second quarter of 2019. PG&E Corporation and the Utility are unable to predict the outcome of this proceeding.

OIR to Implement Public Utilities Code Section 451.2 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 customer harm threshold, 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 (the "Customer Harm Threshold"). 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 Customer Harm Threshold. 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.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Based on the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Based on the OIR, as well as prior experience and precedent, and unless the CPUC alters the position expressed in the OIR, PG&E Corporation and the Utility believe it likely would take several years to obtain authorization to securitize any amounts relating to the 2017 Northern California wildfires.

On February 11, 2019, PG&E Corporation and the Utility filed opening comments in response to the OIR in which they argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt PG&E Corporation and the Utility can raise. Based on assumptions set forth in the comments, PG&E Corporation and the Utility indicated that they could borrow up to approximately $3 billion to fund wildfire claims costs as part of a plan of reorganization.

Transportation Electrification

California Law 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 standard review program proposals for actual expenditures up to approximately $269 million (including $198 million of capital expenditures), to support make-ready infrastructure supporting public fast charging and medium to heavy-duty fleets. In the FleetReady program, the Utility has a goal of providing utility-owned make-ready infrastructure at 700 sites, 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 Fast Charge program has a goal to install 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 pre-hearing conference for this rulemaking is expected in the first quarter of 2019, with a scoping memo to follow that conference.

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.

As part of the Utility's DRP approach, on June 1, 2018, the Utility filed its first annual distribution grid needs assessment report with the CPUC, and on September 4, 2018, the Utility filed its first distribution deferral opportunity report. The distribution deferral report proposes cost effective electric distribution investments that can be deferred through deployment of dispatchable third-party owned DERs, or non-wire alternative solutions, to operate during specific grid events. The Utility convened a distribution planning advisory group comprised of CPUC staff, ratepayer and environmental advocates, and DER market participants, to review and provide advisory input to the Utility on its distribution deferral identification process and to identify distribution deferral opportunities. After incorporating the advisory group's input, on November 28, 2018, the Utility filed a proposal with the CPUC for competitively procuring distribution services from third-party owned DERs to defer selected distribution deferral opportunities. The Utility expects to launch competitive solicitations following the CPUC's approval of the Utility's procurement plan.

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. The grid modernization plan for DERs must include a narrative 10-year vision for investments needed to support DER growth, while ensuring safety and service reliability. On June 25, 2018, the Utility hosted a public grid modernization workshop for integrating DERs to provide a high-level overview of its vision and 10-year plan and incorporate stakeholder input. On December 13, 2018, the Utility filed its 2020 GRC Application, which includes the Utility's grid modernization vision and plan.

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. Phase one will focus on how to integrate climate change adaptation into the IOUs' existing planning and operations to ensure utility safety and reliability.

The CPUC OIR will consider:

- how to define climate change adaption for the IOUs;
- the climate-driven risks facing the IOUs;
- data, tools, resources, and guidance to instruct utilities on how to incorporate adaption in their existing planning and operational processes; and
- strategies to address climate change in CPUC proceedings, including impacts on disadvantaged communities.

On October 10, 2018, the CPUC issued a scoping memo and established a procedural schedule. A final decision is expected in late 2019.

80

LEGISLATIVE AND REGULATORY INITIATIVES

Senate Bill 901

SB 901, signed into law on September 21, 2018, requires the CPUC to establish a Customer Harm Threshold (as defined herein), directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the Customer Harm Threshold. 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 Customer Harm Threshold. 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.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Based on the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs, and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Based on the OIR, as well as prior experience and precedent, and unless the CPUC alters the position expressed in the OIR, PG&E Corporation and the Utility believe it likely would take several years to obtain authorization to securitize any amounts relating to the 2017 Northern California wildfires.

On February 11, 2019, PG&E Corporation and the Utility filed opening comments in response to the OIR. (See "Regulatory Matters - OIR to Implement Public Utilities Code Section 451.2 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 General Rate Case 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.

Finally, SB 901 established a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures. The commission, which will be composed of members with demonstrated expertise in insurance, public and private utilities, or allocation of costs and reduction of damage associated with wildfires, will hold multiple meetings throughout the state to accept public and expert testimony and develop recommendations. The commission, in consultation with the CPUC and California Insurance Commissioner, will prepare a report on or before July 1, 2019, that contains an assessment of issues surrounding catastrophic wildfire costs and damages and makes recommendations for changes to the law. The recommendations of the commission and the response by the Governor and legislature to those recommendations could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Power Charge Indifference Adjustment OIR

On October 11, 2018, the CPUC approved a decision to modify the PCIA methodology, which was developed after the 2001 California energy crisis, which adjusts how customers that leave the Utility's bundled service for CCA or Direct Access service, pay for their share of the costs associated with long-term power purchase commitments made on their behalf. The decision better enables utilities to recover their above market costs from departing customers as compared to the previous methodology, by:

- adopting benchmark values used to set the PCIA rate that more closely resemble actual market prices for resource adequacy and renewable energy credits;
- continuing to allow legacy utility-owned generation costs to be recovered from CCA customers;
- eliminating the 10-year limit on PCIA cost recovery for post-2002 utility owned generation and certain storage costs; and
- adding an annual true-up to the PCIA rate based on market sales.

The Utility anticipates the revised PCIA rate to go into effect as of May 1, 2019.

On December 19, 2018, a prehearing conference was held to initiate phase 2 of the PCIA proceeding, to further develop proposals for future consideration by the CPUC. On February 1, 2019, the assigned commissioner issued a phase 2 scoping memo and ruling, which sets forth the category, issues, need for hearing, schedule, and other matters. As indicated in the scoping memo and ruling, phase 2 of this proceeding will primarily rely upon a working group process to further develop a number of PCIA-related proposals for consideration by the CPUC, which include benchmark true-up for brown power resource adequacy and renewable energy credits, rate design mechanics, portfolio optimization and cost reduction, allocation and auctions, whether the Commission should consider new or modified shareholder responsibility for future portfolio mismanagement, if any, and CCA and DA prepayment options. The schedule included in the scoping memo and ruling indicates that the CPUC is expected to issue decisions on several topics covered by this OIR starting in late 2019 and extending through 2020.

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 14 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 $11 million and $8 million at December 31, 2018 and 2017, respectively. (See Note 9 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, 2018 and 2017, 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 $24 million and $12 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. (See Note 4 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, 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, 2018 | $ 137 | $ (52 ) | $ 85 | 3 | $ 64 |
| December 31, 2017 | $ 40 | $ (16 ) | $ 24 | 2 | $ 12 |

[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.

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 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, 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 wildfire-related claims that will be filed in the Chapter 11 Cases, the number of current and future claims that will be included in a plan of reorganization, how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed, and the impact that historical settlement values for wildfire claims may have on the estimation of wildfire liability in the Chapter 11 Cases.

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 13 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 13 and "Enforcement and Litigation Matters" in Note 14 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 begun 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.

85

At December 31, 2018 and 2017, the Utility's accruals for undiscounted gross environmental liabilities were $1.3 billion and $1.0 billion, respectively. The Utility's undiscounted future costs could increase to as much as $2.5 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 13 and "Other Matters" in Note 14 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 13 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 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2018, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $6.6 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $10.1 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 Customer Harm Threshold. Through December 31, 2018, the Utility has incurred net wildfire-related claims for the 2017 Northern California wildfires in excess of $2.7 billion. The Utility has made an assessment as of December 31, 2018 and has concluded that the net wildfire-related claims 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 2 and 3 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, 2018, 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 3 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 11 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 6.5%, 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 6.0% compares to a ten-year actual return of 10.0%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 1,101 Aa-grade non-callable bonds at December 31, 2018. 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 | Increase in 2018 Pension Costs | Increase in Projected |
| --- | --- | --- | --- |

| | Assumption | | | Benefit Obligation at December 31, 2018 |
|---|---|---|---|---|
| Discount rate | (0.50 )% | $ | 79 | $ 1,265 |
| Rate of return on plan assets | (0.50 )% | 82 | | — |
| Rate of increase in compensation | 0.50 % | 43 | | 286 |

88

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 2018 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2018 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 9 | $ 55 |
| Discount rate | (0.50 )% | 10 | 122 |
| Rate of return on plan assets | (0.50 )% | 12 | — |

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2 of the Notes to the Consolidated Financial Statements.

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 pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to 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,” “antic “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, the ability to develop and obtain applicable Bankruptcy Court, creditor or 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 U.S. District 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, disruptions to PG&E Corporation’s and the Utility’s business and operations and the potential impact on regulatory compliance;

- 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;

- increased employee attrition as a result of the filing 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;
- the potential delay in emergence from bankruptcy if PG&E Corporation and the Utility are not able to develop and consummate a consensual plan of reorganization and are forced to engage in a contested proceeding;
- the possibility that the DIP Credit Agreement is not sufficient to fund PG&E Corporation's and the Utility's cash requirements through their emergence from bankruptcy;
- the possibility that PG&E Corporation and the Utility may not be able to obtain exit financing on favorable terms or at all;
- the outcome of the U.S. District Court matters and probation;
- 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 in excess of the Utility's currently authorized revenue requirements; 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 and determined that the Utility failed to comply with applicable laws and regulations;
- the timing and outcome of claims arising from the 2015 Butte fire and the timing and outcome of any proceeding to recover related costs in excess of insurance through rates; the effect, if any, that the SED's $8.3 million citations issued in connection with the 2015 Butte fire may have on the claims arising from the 2015 Butte fire; and whether additional investigations and proceedings in connection with the 2015 Butte fire will be opened and any additional fines or penalties imposed on the Utility;
- the timing and outcome of issuance of recovery bonds ("securitization") of 2017 Northern California wildfires costs that the CPUC finds just and reasonable;
- whether PG&E Corporation and the Utility are able to successfully challenge the application of the doctrine of inverse condemnation to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire;
- the timing and outcome of future regulatory and legislative developments in connection with SB 901, including the Customer Harm Threshold in connection with the 2017 Northern California wildfires, future wildfire reforms, inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures or other reforms targeted at the Utility;
- the outcome of the Utility's community wildfire safety program 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; 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;

- the timing and outcomes of the 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19, and TO20 rate cases, 2018 CEMA, future applications for WEMA and FHPMA, future cost of capital proceeding, and other ratemaking and regulatory proceedings;

90

- 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, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the effects on PG&E Corporation's and the Utility's reputations caused by the CPUC's investigations of natural gas and electric incidents, the 2018 Camp fire and 2017 Northern California wildfires, locate and mark, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the implementation of the Safety Culture OII decision approved on November 29, 2018, and the outcome of its phase two 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 implement corporate governance changes;

- whether the Utility can control its 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 of the October 1, 2018 request for rehearing of FERC's denial 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 ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC's decision granting the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;

- 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 timing and outcome of any CPUC action in connection with the Utility's SmartMeter™ Upgrade cost-benefit analysis;

- 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 RPS-eligible or carbon-free resources by 2045;

- how the CPUC and the California Air Resources Board 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 customer demand for electricity and natural gas 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, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Utility's procurement service for CCAs;

- 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 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;

- 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.

92

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 above and a detailed discussion of these matters contained elsewhere in 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.

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 "News & Events: Events & Presentations" tab and links to certain documents and information related to the 2018 Camp fire, the 2017 Northern California wildfires, the 2015 Butte fire, and other updates which may be of interest to investors, at http://investor.pgecorp.com, under the "Wildfire Updates" tab, 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 this website is 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 this website solely for the information of investors and do not intend the address to be an active link.

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 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PG&E Corporation
CONSOLIDATED STATEMENTS OF INCOME
(in millions, except per share amounts)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Operating Revenues | | | |
| Electric | $12,713 | $13,124 | $13,864 |
| Natural gas | 4,046 | 4,011 | 3,802 |
| Total operating revenues | 16,759 | 17,135 | 17,666 |
| Operating Expenses | | | |
| Cost of electricity | 3,828 | 4,309 | 4,765 |
| Cost of natural gas | 671 | 746 | 615 |
| Operating and maintenance | 7,153 | 6,321 | 7,326 |
| Wildfire-related claims, net of insurance recoveries | 11,771 | — | 125 |
| Depreciation, amortization, and decommissioning | 3,036 | 2,854 | 2,755 |
| Total operating expenses | 26,459 | 14,230 | 15,586 |
| Operating Income (Loss) | (9,700) | 2,905 | 2,080 |
| Interest income | 76 | 31 | 23 |
| Interest expense | (929) | (888) | (829) |
| Other income, net | 424 | 123 | 188 |
| Income (Loss) Before Income Taxes | (10,129) | 2,171 | 1,462 |
| Income tax provision (benefit) | (3,292) | 511 | 55 |
| Net Income (Loss) | (6,837) | 1,660 | 1,407 |
| Preferred stock dividend requirement of subsidiary | 14 | 14 | 14 |
| Income (Loss) Available for Common Shareholders | $(6,851) | $1,646 | $1,393 |
| Weighted Average Common Shares Outstanding, Basic | 517 | 512 | 499 |
| Weighted Average Common Shares Outstanding, Diluted | 517 | 513 | 501 |
| Net Earnings (Loss) Per Common Share, Basic | $(13.25) | $3.21 | $2.79 |
| Net Earnings (Loss) Per Common Share, Diluted | $(13.25) | $3.21 | $2.78 |

See accompanying Notes to the Consolidated Financial Statements.

94

PG&E Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Net Income (Loss) | $(6,837) | $1,660 | $1,407 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $2, $0, and $1, at respective dates) | 4 | 1 | (2) |
| Total other comprehensive income (loss) | 4 | 1 | (2) |
| Comprehensive Income (Loss) | (6,833) | 1,661 | 1,405 |
| Preferred stock dividend requirement of subsidiary | 14 | 14 | 14 |
| Comprehensive Income (Loss) Attributable to Common Shareholders | $(6,847) | $1,647 | $1,391 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

| | Balance at December 31, 2018 | | 2017 | |
|---|---|---|---|---|
| ASSETS | | | | |
| Current Assets | | | | |
| Cash and cash equivalents | $ | 1,668 | $ | 449 |
| Accounts receivable | | | | |
| Customers (net of allowance for doubtful accounts of $56 and $64 at respective dates) | 1,148 | | 1,243 | |
| Accrued unbilled revenue | 1,000 | | 946 | |
| Regulatory balancing accounts | 1,435 | | 1,222 | |
| Other | 2,686 | | 861 | |
| Regulatory assets | 233 | | 615 | |
| Inventories | | | | |
| Gas stored underground and fuel oil | 111 | | 115 | |
| Materials and supplies | 443 | | 366 | |
| Income taxes receivable | 23 | | — | |
| Other | 448 | | 464 | |
| Total current assets | 9,195 | | 6,281 | |
| Property, Plant, and Equipment | | | | |
| Electric | 59,150 | | 55,133 | |
| Gas | 21,556 | | 19,641 | |
| Construction work in progress | 2,564 | | 2,471 | |
| Other | 2 | | 3 | |
| Total property, plant, and equipment | 83,272 | | 77,248 | |
| Accumulated depreciation | (24,715 | ) | (23,459 | ) |
| Net property, plant, and equipment | 58,557 | | 53,789 | |
| Other Noncurrent Assets | | | | |
| Regulatory assets | 4,964 | | 3,793 | |
| Nuclear decommissioning trusts | 2,730 | | 2,863 | |
| Income taxes receivable | 69 | | 65 | |
| Other | 1,480 | | 1,221 | |
| Total other noncurrent assets | 9,243 | | 7,942 | |
| TOTAL ASSETS | $ | 76,995 | $ | 68,012 |

See accompanying Notes to the Consolidated Financial Statements.

96

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

| | Balance at December 31, 2018 | 2017 |
|---|---|---|
| LIABILITIES AND EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | $3,435 | $931 |
| Long-term debt, classified as current | 18,559 | 445 |
| Accounts payable | | |
| Trade creditors | 1,975 | 1,646 |
| Regulatory balancing accounts | 1,076 | 1,120 |
| Other | 464 | 517 |
| Disputed claims and customer refunds | 220 | 243 |
| Interest payable | 228 | 217 |
| Wildfire-related claims | 14,226 | 561 |
| Other | 1,512 | 1,449 |
| Total current liabilities | 41,695 | 7,129 |
| Noncurrent Liabilities | | |
| Long-term debt | — | 17,753 |
| Regulatory liabilities | 8,539 | 8,679 |
| Pension and other postretirement benefits | 2,119 | 2,128 |
| Asset retirement obligations | 5,994 | 4,899 |
| Deferred income taxes | 3,281 | 5,822 |
| Other | 2,464 | 2,130 |
| Total noncurrent liabilities | 22,397 | 41,411 |
| Contingencies and Commitments (Notes 13 and 14) | | |
| Equity | | |
| Shareholders' Equity | | |
| Common stock, no par value, authorized 800,000,000 shares; 520,338,710 and 514,755,845 shares outstanding at respective dates | 12,910 | 12,632 |
| Reinvested earnings | (250) | 6,596 |
| Accumulated other comprehensive loss | (9) | (8) |
| Total shareholders' equity | 12,651 | 19,220 |
| Noncontrolling Interest - Preferred Stock of Subsidiary | 252 | 252 |
| Total equity | 12,903 | 19,472 |
| TOTAL LIABILITIES AND EQUITY | $76,995 | $68,012 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Cash Flows from Operating Activities | | | |
| Net income (loss) | $(6,837) | $1,660 | $1,407 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 3,036 | 2,854 | 2,755 |
| Allowance for equity funds used during construction | (129) | (89) | (112) |
| Deferred income taxes and tax credits, net | (2,532) | 1,254 | 1,030 |
| Disallowed capital expenditures | (45) | 47 | 507 |
| Other | 332 | 307 | 379 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (121) | 67 | (473) |
| Wildfire-related insurance receivable | (1,698) | (21) | (575) |
| Inventories | (73) | (18) | (24) |
| Accounts payable | 409 | 173 | 180 |
| Wildfire-related claims | 13,665 | (129) | 690 |
| Income taxes receivable/payable | (23) | 160 | (5) |
| Other current assets and liabilities | (281) | 42 | 83 |
| Regulatory assets, liabilities, and balancing accounts, net | (800) | (387) | (1,214) |
| Other noncurrent assets and liabilities | (151) | 57 | (219) |
| Net cash provided by operating activities | 4,752 | 5,977 | 4,409 |
| Cash Flows from Investing Activities | | | |
| Capital expenditures | (6,514) | (5,641) | (5,709) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,412 | 1,291 | 1,295 |
| Purchases of nuclear decommissioning trust investments | (1,485) | (1,323) | (1,352) |
| Other | 23 | 23 | 13 |
| Net cash used in investing activities | (6,564) | (5,650) | (5,753) |
| Cash Flows from Financing Activities | | | |
| Borrowings under revolving credit facilities | 3,960 | — | — |
| Repayments under revolving credit facilities | (775) | — | — |
| Net issuances (repayments) of commercial paper, net of discount of $1, $5, and $6 at respective dates | (182) | (840) | (9) |
| Short-term debt financing | 600 | 750 | 500 |
| Short-term debt matured | (750) | (500) | — |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $7, $32, and $17 at respective dates | 793 | 2,713 | 983 |
| Long-term debt matured or repurchased | (795) | (1,445) | (160) |
| Common stock issued | 200 | 395 | 822 |
| Common stock dividends paid | — | (1,021) | (921) |
| Other | (20) | (107) | (44) |
| Net cash provided by (used in) financing activities | 3,031 | (55) | 1,171 |
| Net change in cash, cash equivalents, and restricted cash | 1,219 | 272 | (173) |
| Cash, cash equivalents, and restricted cash at January 1 | 456 | 184 | 357 |
| Cash, cash equivalents, and restricted cash at December 31 | $1,675 | $456 | $184 |
| Less: Restricted cash and restricted cash equivalents | (7) | (7) | (7) |
| Cash and cash equivalents at December 31 | $1,668 | $449 | $177 |

98

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| | | | |
|---|---|---|---|
| Supplemental disclosures of cash flow information | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $(786) | $(790) | $(726) |
| Income taxes, net | (49 ) | 162 | 231 |
| Supplemental disclosures of noncash investing and financing activities | | | |
| Common stock dividends declared but not yet paid | $— | $— | $248 |
| Capital expenditures financed through accounts payable | 368 | 501 | 403 |
| Noncash common stock issuances | — | 21 | 20 |

See accompanying Notes to the Consolidated Financial Statements.

99

PG&E Corporation
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, 2015 | 492,025,443 | $ 11,282 | $ 5,301 | $ (7) | $ 16,576 | $ 252 | $ 16,828 |
| Cumulative effect of change in accounting principle | — | — | 29 | — | 29 | — | 29 |
| Net income | — | — | 1,407 | — | 1,407 | — | 1,407 |
| Other comprehensive income | — | — | — | (2) | (2) | — | (2) |
| Common stock issued, net | 14,866,431 | 842 | — | — | 842 | — | 842 |
| Stock-based compensation amortization | — | 74 | — | — | 74 | — | 74 |
| Common stock dividends declared | — | — | (972) | — | (972) | — | (972) |
| Preferred stock dividend requirement of subsidiary | — | — | (14) | — | (14) | — | (14) |
| 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 loss | — | — | — | 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 income (loss) | — | — | (6,837) | — | (6,837) | — | (6,837) |
| Other comprehensive 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 |

See accompanying Notes to the Consolidated Financial Statements.

100

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Operating Revenues | | | |
| Electric | $12,713 | $13,127 | $13,865 |
| Natural gas | 4,047 | 4,011 | 3,802 |
| Total operating revenues | 16,760 | 17,138 | 17,667 |
| Operating Expenses | | | |
| Cost of electricity | 3,828 | 4,309 | 4,765 |
| Cost of natural gas | 671 | 746 | 615 |
| Operating and maintenance | 7,153 | 6,383 | 7,327 |
| Wildfire-related claims, net of insurance recoveries | 11,771 | — | 125 |
| Depreciation, amortization, and decommissioning | 3,036 | 2,854 | 2,754 |
| Total operating expenses | 26,459 | 14,292 | 15,586 |
| Operating Income (Loss) | (9,699 ) | 2,846 | 2,081 |
| Interest income | 74 | 30 | 22 |
| Interest expense | (914 ) | (877 ) | (819 ) |
| Other income, net | 426 | 119 | 188 |
| Income (Loss) Before Income Taxes | (10,113 ) | 2,118 | 1,472 |
| Income tax provision (benefit) | (3,295 ) | 427 | 70 |
| Net Income (Loss) | (6,818 ) | 1,691 | 1,402 |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| Income (Loss) Available for Common Stock | $(6,832 ) | $1,677 | $1,388 |

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Net Income (Loss) | $(6,818) | $1,691 | $1,402 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $2, $3, and $1, at respective dates) | (5) | 4 | (1) |
| Total other comprehensive income (loss) | (5) | 4 | (1) |
| Comprehensive Income (Loss) | $(6,823) | $1,695 | $1,401 |

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions)

| | Balance at December 31, 2018 | | 2017 | |
|---|---|---|---|---|
| ASSETS | | | | |
| Current Assets | | | | |
| Cash and cash equivalents | $ 1,295 | | $ 447 | |
| Accounts receivable | | | | |
| Customers (net of allowance for doubtful accounts of $56 and $64 at respective dates) | 1,148 | | 1,243 | |
| Accrued unbilled revenue | 1,000 | | 946 | |
| Regulatory balancing accounts | 1,435 | | 1,222 | |
| Other | 2,688 | | 862 | |
| Regulatory assets | 233 | | 615 | |
| Inventories | | | | |
| Gas stored underground and fuel oil | 111 | | 115 | |
| Materials and supplies | 443 | | 366 | |
| Income taxes receivable | 5 | | — | |
| Other | 448 | | 465 | |
| Total current assets | 8,806 | | 6,281 | |
| Property, Plant, and Equipment | | | | |
| Electric | 59,150 | | 55,133 | |
| Gas | 21,556 | | 19,641 | |
| Construction work in progress | 2,564 | | 2,471 | |
| Total property, plant, and equipment | 83,270 | | 77,245 | |
| Accumulated depreciation | (24,713 | ) | (23,456 | ) |
| Net property, plant, and equipment | 58,557 | | 53,789 | |
| Other Noncurrent Assets | | | | |
| Regulatory assets | 4,964 | | 3,793 | |
| Nuclear decommissioning trusts | 2,730 | | 2,863 | |
| Income taxes receivable | 66 | | 64 | |
| Other | 1,348 | | 1,094 | |
| Total other noncurrent assets | 9,108 | | 7,814 | |
| TOTAL ASSETS | $ 76,471 | | $ 67,884 | |

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

| | Balance at December 31, | |
|---|---|---|
| | 2018 | 2017 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | $3,135 | $799 |
| Long-term debt, classified as current | 18,209 | 445 |
| Accounts payable | | |
| Trade creditors | 1,972 | 1,644 |
| Regulatory balancing accounts | 1,076 | 1,120 |
| Other | 498 | 538 |
| Disputed claims and customer refunds | 220 | 243 |
| Interest payable | 227 | 214 |
| Wildfire-related claims | 14,226 | 561 |
| Other | 1,497 | 1,457 |
| Total current liabilities | 41,060 | 7,021 |
| Noncurrent Liabilities | | |
| Long-term debt | — | 17,403 |
| Regulatory liabilities | 8,539 | 8,679 |
| Pension and other postretirement benefits | 2,026 | 2,026 |
| Asset retirement obligations | 5,994 | 4,899 |
| Deferred income taxes | 3,405 | 5,963 |
| Other | 2,492 | 2,146 |
| Total noncurrent liabilities | 22,456 | 41,116 |
| Contingencies and Commitments (Notes 13 and 14) | | |
| 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 | 8,505 |
| Reinvested earnings | 2,826 | 9,656 |
| Accumulated other comprehensive (loss) income | (1 ) | 6 |
| Total shareholders' equity | 12,955 | 19,747 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | $76,471 | $67,884 |

See accompanying Notes to the Consolidated Financial Statements.

104

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Cash Flows from Operating Activities | | | |
| Net income (loss) | $(6,818) | $1,691 | $1,402 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 3,036 | 2,854 | 2,754 |
| Allowance for equity funds used during construction | (129) | (89) | (112) |
| Deferred income taxes and tax credits, net | (2,548) | 1,103 | 1,042 |
| Disallowed capital expenditures | (45) | 47 | 507 |
| Other | 258 | 283 | 306 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (122) | 66 | (475) |
| Wildfire-related insurance receivable | (1,698) | (21) | (575) |
| Inventories | (73) | (18) | (24) |
| Accounts payable | 421 | 173 | 179 |
| Wildfire-related claims | 13,665 | (129) | 690 |
| Income taxes receivable/payable | (5) | 159 | (29) |
| Other current assets and liabilities | (301) | 59 | 112 |
| Regulatory assets, liabilities, and balancing accounts, net | (800) | (390) | (1,214) |
| Other noncurrent assets and liabilities | (137) | 128 | (219) |
| Net cash provided by operating activities | 4,704 | 5,916 | 4,344 |
| Cash Flows from Investing Activities | | | |
| Capital expenditures | (6,514) | (5,641) | (5,709) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,412 | 1,291 | 1,295 |
| Purchases of nuclear decommissioning trust investments | (1,485) | (1,323) | (1,352) |
| Other | 23 | 23 | 13 |
| Net cash used in investing activities | (6,564) | (5,650) | (5,753) |
| Cash Flows from Financing Activities | | | |
| Borrowings under revolving credit facilities | 3,535 | — | — |
| Repayments under revolving credit facilities | (650) | — | — |
| Net issuances (repayments) of commercial paper, net of discount of $0, $5, and $6 at respective dates | (50) | (972) | (9) |
| Short-term debt financing | 250 | 750 | 500 |
| Short-term debt matured | (750) | (500) | — |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $7, $32, and $17 at respective dates | 793 | 2,713 | 983 |
| Long-term debt matured or repurchased | (445) | (1,445) | (160) |
| Preferred stock dividends paid | — | (14) | (14) |
| Common stock dividends paid | — | (784) | (911) |
| Equity contribution from PG&E Corporation | 45 | 455 | 835 |
| Other | (20) | (93) | (30) |
| Net cash provided by financing activities | 2,708 | 110 | 1,194 |
| Net change in cash, cash equivalents, and restricted cash | 848 | 376 | (215) |
| Cash, cash equivalents, and restricted cash at January 1 | 454 | 78 | 293 |
| Cash, cash equivalents, and restricted cash at December 31 | $1,302 | $454 | $78 |
| Less: Restricted cash and restricted cash equivalents | (7) | (7) | (7) |

| | | | |
|---|---|---|---|
| Cash and cash equivalents at December 31 | $1,295 | $447 | $71 |

| | | | |
|---|---|---|---|
| Supplemental disclosures of cash flow information | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $(773) | $(781) | $(717) |
| Income taxes, net | (59) | 162 | 244 |
| Supplemental disclosures of noncash investing and financing activities | | | |
| Capital expenditures financed through accounts payable | $368 | $501 | $403 |

See accompanying Notes to the Consolidated Financial Statements.

106

Pacific Gas and Electric Company
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, 2015 | $ 258 | $ 1,322 | $ 7,215 | $ 8,262 | $ 3 | $ 17,060 |
| Cumulative effect of change in accounting principle | — | — | — | 24 | — | 24 |
| Net income | — | — | — | 1,402 | — | 1,402 |
| Other comprehensive income | — | — | — | — | (1) | (1) |
| Equity contribution | — | — | 835 | — | — | 835 |
| Common stock dividend | — | — | — | (911) | — | (911) |
| Preferred stock dividend | — | — | — | (14) | — | (14) |
| Balance at December 31, 2016 | $ 258 | $ 1,322 | $ 8,050 | $ 8,763 | $ 2 | $ 18,395 |
| Net income | — | — | — | 1,691 | — | 1,691 |
| Other comprehensive loss | — | — | — | — | 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 income (loss) | — | — | — | (6,818) | — | (6,818) |
| Other comprehensive 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 |

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, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management’s estimates or assumptions could result in an adjustment that could have a material 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 are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. See Note 13 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 is 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. See Note 15 below. 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 Chapter 11, 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 4 and Note 15 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 confirmed 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.

NOTE 2: 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.

The FERC authorizes the Utility’s revenue requirements in periodic TO rate cases. The Utility’s ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility’s electricity sales, and revenue is recognized only for amounts billed and unbilled, net of a reserve for revenues subject to refund.

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 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 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 December 31, 2018 |
|---|---|
| Electric | |
| Revenue from contracts with customers | |
| Residential | $ 5,051 |
| Commercial | 4,908 |
| Industrial | 1,532 |
| Agricultural | 1,234 |
| Public street and highway lighting | 72 |
| Other [1] | (720 ) |
| Total revenue from contracts with customers - electric | 12,077 |
| Regulatory balancing accounts [2] | 636 |
| Total electric operating revenue | $ 12,713 |
| | |
| Natural gas | |
| Revenue from contracts with customers | |
| Residential | $ 2,042 |
| Commercial | 537 |
| Transportation service only | 1,151 |
| Other [1] | 75 |
| Total revenue from contracts with customers - gas | 3,805 |
| Regulatory balancing accounts [2] | 242 |
| Total natural gas operating revenue | 4,047 |
| Total operating revenues | $ 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:

| | Estimated Useful | Balance at December 31, | |
|---|---|---|---|
| (in millions, except estimated useful lives) | Lives (years) | 2018 | 2017 |
| Electricity generating facilities [1] | 5 to 120 | $13,047 | $11,843 |
| Electricity distribution facilities | 15 to 65 | 32,926 | 31,110 |
| Electricity transmission facilities | 15 to 75 | 13,177 | 12,180 |
| Natural gas distribution facilities | 20 to 60 | 13,296 | 12,312 |
| Natural gas transmission and storage facilities | 5 to 62 | 8,260 | 7,329 |
| Construction work in progress | | 2,564 | 2,471 |
| Total property, plant, and equipment | | 83,270 | 77,245 |
| Accumulated depreciation | | (24,713 ) | (23,456 ) |
| Net property, plant, and equipment | | $58,557 | $53,789 |

[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 14 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 3.82% in 2018, 3.83% in 2017, and 3.73% in 2016. 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 $53 million and $129 million during 2018, $38 million and $89 million during 2017, and $51 million and $112 million during 2016.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2018 and 2017, including nuclear decommissioning obligations:

| (in millions) | 2018 | 2017 |
|---|---|---|
| ARO liability at beginning of year | $4,899 | $4,684 |
| Revision in estimated cash flows | 993 | 128 |
| Accretion | 211 | 207 |
| Liabilities settled | (109 ) | (120 ) |
| ARO liability at end of year | $5,994 | $4,899 |

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, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration of land to the conditions under certain agreements.

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility’s nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In December 2018, the Utility submitted its updated decommissioning cost estimate to the CPUC and correspondingly increased its ARO liabilities by $1.1 billion. The adjustment was a result of increased estimated costs based on a site-specific decommissioning analysis. 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 $4.7 billion and $3.5 billion at December 31, 2018 and 2017, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility’s nuclear power plants was $10.6 billion and $7.0 billion at December 31, 2018 and 2017, respectively.

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 14 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, 2018, 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, 2018, it did not consolidate any of them.

Other Accounting Policies

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Notes 13 and 14 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, 2018 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| Beginning balance | $ (25 ) | $ 17 | $ (8 ) |
| Other comprehensive income before reclassifications: | | | |
| Unrecognized net actuarial loss (net of taxes of $41 and $9, respectively) | (104 ) | (23 ) | (127) |
| Regulatory account transfer (net of taxes of $41 and $9, respectively) | 107 | 23 | 130 |
| Amounts reclassified from other comprehensive income: | | | |
| Amortization of prior service cost (net of taxes of $2 and $4, respectively) [1] | (4 ) | 10 | 6 |
| Amortization of net actuarial loss (net of taxes of $2 and $1, respectively) [1] | 3 | (4 ) | (1 ) |
| Regulatory account transfer (net of taxes of $1 and $3, respectively) [1] | 2 | (6 ) | (4 ) |
| Net current period other comprehensive loss | 4 | — | 4 |
| Ending balance | $ (21 ) | $ 17 | $ (4 ) |

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

113

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2017 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| Beginning balance | $ (25 ) | $ 16 | $ (9 ) |
| Other comprehensive income before reclassifications: | | | |
| Unrecognized prior service cost (net of taxes of $4 and $0, respectively) | (6 ) | — | (6 ) |
| Unrecognized net actuarial loss (net of taxes of $229 and $97, respectively) | 333 | 141 | 474 |
| Regulatory account transfer (net of taxes of $225 and $97, respectively) | (327 ) | (141 ) | (468) |
| Amounts reclassified from other comprehensive income: | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) (1) | (4 ) | 9 | 5 |
| Amortization of net actuarial loss (net of taxes of $9 and $2, respectively) (1) | 13 | 2 | 15 |
| Regulatory account transfer (net of taxes of $6 and $8, respectively) (1) | (9 ) | (10 ) | (19 ) |
| Net current period other comprehensive loss | — | 1 | 1 |
| Ending balance | $ (25 ) | $ 17 | $ (8 ) |

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

Recently Adopted Accounting Standards

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-9, Revenue from Contracts with Customers (Topic 606), which amends the previous revenue recognition guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. PG&E Corporation and the Utility applied the requirements using the modified retrospective method when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Consolidated Financial Statements as of the adoption date or for the year ended December 31, 2018. A majority of the Utility's revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customers' monthly consumption. Such revenue is recognized using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer. See "Revenue Recognition" above.

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows – Restricted Cash (Topic 230), which amends the existing guidance relating to the disclosure of restricted cash and restricted cash equivalents on the statement of cash flows. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning and end of period total amounts shown on the statement of cash flows. Previously, changes in restricted cash were reported within cash flows from investing activities. PG&E Corporation and the Utility applied the requirements on a retrospective basis when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Consolidated Financial Statements as of the adoption date or for the year ended December 31, 2018.

The retrospective adjustments to the Consolidated Statements of Cash Flows for PG&E Corporation and the Utility resulted in an increase to Net cash used in investing activities of $227 million, an increase to Cash, cash equivalents and restricted cash at January 1 by $234 million, and an increase to Cash, cash equivalents and restricted cash at December 31 by $7 million for the year ended December 31, 2016.

Presentation of Net Periodic Pension and Post-Retirement Benefit Costs

In March 2017, the FASB issued ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715), which amends the guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. PG&E Corporation and the Utility applied the requirements when the ASU became effective on January 1, 2018.

On a retrospective basis, the amendment requires an employer to separate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. As a result, the Consolidated Statements of Income for PG&E Corporation and the Utility were restated. This change resulted in increases to Operating and maintenance expenses and Other income, net, of $51 million and $54 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2017 and $97 million and $100 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2016.

On a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The FERC has allowed and the Utility has made a one-time election to adopt the new FASB guidance for regulatory filing purposes. In January 2018, the CPUC approved modifications to the Utility's calculation for pension-related revenue requirements to allow for capitalization of only the service cost component determined by a plan's actuary. The capitalization of service costs only results in higher rate base and a reduction in the Utility's 2018 revenues. The changes in capitalization of retirement benefits did not have a material impact on PG&E Corporation's and the Utility's Consolidated Financial Statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, which amends the guidance relating to the recognition, measurement, presentation, and disclosure of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts and gains or losses are refundable or recoverable, respectively, from customers through rates, therefore gains and losses are deferred and recognized as regulatory assets or liabilities. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 and did not have a material impact on the Consolidated Financial Statements and related disclosures.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, the FASB issued ASU No. 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Act. When amounts are reclassified from accumulated other comprehensive income to the Consolidated Statement of Income, PG&E Corporation and the Utility recognize the related income tax expense at the tax rate in effect at that time. The ASU is effective for PG&E Corporation and the Utility on January 1, 2019, and early adoption is permitted. PG&E Corporation and the Utility early adopted this ASU on January 1, 2018, resulting in an immaterial reclassification.

Accounting Standards Issued But Not Yet Adopted

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the guidance relating to the definition of a lease, recognition of ROU assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. Under the new standard, all lessees must recognize an ROU asset and lease liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU became effective for PG&E Corporation and the Utility 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. Additionally, PG&E Corporation and the Utility do not intend to restate comparative periods upon adoption.

PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility will apply the requirements using the modified retrospective method. PG&E Corporation and the Utility expect this standard to increase ROU assets and liabilities by approximately $2.5 billion to $3.0 billion on the Consolidated Balance Sheets and will result in additional footnote disclosures, but do not expect the guidance will have a material impact on the Consolidated Statements of Income and Statements of Cash Flows. The majority of PG&E Corporation and the Utility's leases are power purchase agreements.

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. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

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 will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

| | Balance at December 31, | | Recovery Period |
|---|---|---|---|
| (in millions) | 2018 | 2017 | |
| Pension benefits [1] | $1,947 | $1,954 | Indefinitely |
| Environmental compliance costs | 1,013 | 837 | 32 years |
| Utility retained generation [2] | 274 | 319 | 8 years |
| Price risk management | 90 | 65 | 10 years |
| Unamortized loss, net of gain, on reacquired debt | 76 | 79 | 25 years |
| Catastrophic event memorandum account [3] | 790 | 274 | TBD years |
| Wildfire expense memorandum account [4] | 94 | — | TBD years |
| Fire hazard prevention memorandum account [5] | 263 | 1 | TBD years |
| Other | 417 | 264 | Various |
| Total long-term regulatory assets | $4,964 | $3,793 | |

(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 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.

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.

117

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2018 | 2017 |
|---|---|---|
| Cost of removal obligations [1] | $5,981 | $5,547 |
| Deferred income taxes [2] | 283 | 1,021 |
| Recoveries in excess of AROs [3] | 356 | 624 |
| Public purpose programs [4] | 674 | 590 |
| Retirement Plan [5] | 421 | 418 |
| Other | 824 | 479 |
| Total long-term regulatory liabilities | $8,539 | $8,679 |

[1] Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.
[2] Represents the net of amounts owed to customers for deferred taxes collected at higher rates before the Tax Act and amounts owed to the Utility for reversal of deferred taxes subject to flow-through treatment. (See Note 8 below.)
[3] Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 10 below.)
[4] Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.
[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, 2018 | 2017 |
|---|---|---|
| Electric distribution | $160 | $— |
| Electric transmission | 128 | 139 |
| Utility generation | 79 | — |
| Gas distribution and transmission | 462 | 486 |
| Energy procurement | 168 | 71 |

| | | |
|---|---|---|
| Public purpose programs | 111 | 103 |
| Other | 327 | 423 |
| Total regulatory balancing accounts receivable | $1,435 | $1,222 |

| (in millions) | Payable Balance at December 31, 2018 | 2017 |
|---|---|---|
| Electric distribution | $— | $72 |
| Electric transmission | 134 | 120 |
| Utility generation | — | 14 |
| Gas distribution and transmission | 9 | — |
| Energy procurement | 59 | 149 |
| Public purpose programs | 587 | 452 |
| Other | 287 | 313 |
| Total regulatory balancing accounts payable | $1,076 | $1,120 |

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 4: DEBT

Debtor In Possession ("DIP") Facilities

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into a Senior Secured Superpriority Debtor in Possession Credit, Guaranty and Security Agreement, dated as of February 1, 2019 (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.

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 PG&E Corporation and the Utility. As of February 28, 2019, 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 are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all.

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 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 equal to 0.25% of the then-outstanding loans and available commitments. Borrowings under the DIP Facilities will bear interest based, at the Utility's election, on (1) LIBOR plus an applicable margin or (2) ABR plus an applicable margin. 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. With respect to the DIP Revolving Facility, the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility, the applicable margin is 2.25% for LIBOR loans and 1.25% for ABR loans.

The Utility is also required to pay unused fees of (i) 0.375% per annum in respect of the average daily unutilized commitments under the DIP Revolving Facility and (ii) 1.125% per annum, which amount shall increase to 2.25% per annum after six months, in respect of the average daily unutilized commitments under the DIP Delayed Draw Term Loan 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, the final order approving the DIP Facilities failing to have been entered by April 15, 2019, and certain other events related to the impairment of the DIP Lenders' rights or liens granted under the DIP Credit Agreement.

The proceeds of the borrowings under the DIP Facilities will 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.

Long-Term Debt

Debt Obligations Previously Classified as Long Term

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

| (in millions) | | December 31, 2018 | 2017 |
|---|---|---|---|
| PG&E Corporation | | | |
| Term Loan: | | | |
| Stated Maturity | Interest Rates | | |
| 2020 | variable rate [(2)] | 350 | 350 |
| Less: Current Portion [(1)] | | (350) | — |
| Total PG&E Corporation long-term debt | | — | 350 |
| Utility | | | |
| Senior notes: | | | |
| Stated Maturity | Interest Rates | | |
| 2018 | 8.25% | — | 400 |
| 2020 | 3.50% | 800 | 800 |
| 2021 | 3.25% to 4.25% | 550 | 550 |
| 2022 | 2.45% | 400 | 400 |
| 2023 through 2046 | 2.95% to 6.35% | 15,775 | 14,975 |
| Unamortized discount, net of premium and debt issuance costs | | (178) | (185) |
| Less: current portion [(1)] | | (17,347) | (400) |
| Total senior notes, net of current portion | | — | 16,540 |
| Pollution control bonds: | | | |
| Stated Maturity | Interest Rates | | |
| Series 2008 G, due 2018 | 1.05% | — | 45 |
| Series 2008 F and 2010 E, due 2026 [(3)] | 1.75% | 100 | 100 |
| Series 2009 A-B, due 2026 [(4)] | variable rate [(5)] | 149 | 149 |
| Series 1996 C, E, F, 1997 B due 2026 [(4)] | variable rate [(6)] | 614 | 614 |
| Less: current portion [(1)] | | (863) | (45) |
| Total pollution control bonds | | — | 863 |
| Total Utility long-term debt, net of current portion | | — | 17,403 |
| Total consolidated long-term debt, net of current portion | | $— | $17,753 |

[(1)] On January 29, 2019, PG&E Corporation and the Utility commenced reorganization under Chapter 11 of the U.S. Bankruptcy Code. The commencement of the Chapter 11 Cases constituted an event of default or termination event under the above-referenced debt of PG&E Corporation and the Utility. With the exception of Pollution Control Bonds series 2008F and 2010E, where a trustee notice is required to trigger acceleration, the commencement of the Chapter 11 Cases caused an automatic and immediate acceleration of such debt, and the possibility of cure is uncertain. Therefore, all long-term debt is classified as current as of December 31, 2018.
[(2)] At December 31, 2018, the interest rate on the Term Loan was 3.66%.
[(3)] Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 31, 2022.
[(4)] Each series of these bonds is supported by a separate direct-pay letter of credit. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent. Series 2009 A-B bonds have a maturity date of June 5, 2019. In December 2015, Series 1996 C, E, F, 1997 B bonds the letters of credit were extended to

December 1, 2020. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(5) At December 31, 2018, the interest rate on these bonds was 2.08%.

(6) At December 31, 2018, the interest rate on these bonds ranged from 2.05% to 2.15%.

121

Pollution Control Bonds

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

Repayment Schedule

PG&E Corporation's and the Utility's 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, 2018 are reflected in the table below:

| (in millions, except interest rates) | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| PG&E Corporation | | | | | | | |
| Variable interest rate as of December 31, 2018 | — % | 3.51 % | — % | — % | — % | — % | 3.51 % |
| Variable rate obligations | $— | $350 | $— | $— | $— | $— | $350 |
| Utility | | | | | | | |
| Average fixed interest rate | — % | 3.50 % | 3.80 % | 2.31 % | 3.83 % | 4.74 % | 4.52 % |
| Fixed rate obligations | $— | $800 | $550 | $500 | $1,175 | $14,600 | $17,625 |
| Variable interest rate as of December 31, 2018 | 1.78 % | 1.59 % | — % | — % | — % | — % | 1.63 % |
| Variable rate obligations [1] | $149 | $614 | $— | $— | $— | $— | $763 |
| Total consolidated debt | $149 | $1,764 | $550 | $500 | $1,175 | $14,600 | $18,738 |

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

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings and availability under their revolving credit facilities and commercial paper programs at December 31, 2018:

| (in millions) | Termination Date | Credit Facility Limit | Borrowings Against Revolver | Commercial Paper Outstanding | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2022 | $300 (1) | $ 300 | $ — | $ — |
| Utility | April 2022 | $3,000 (2) | $ 2,965 (3) | $ — | $ 35 |
| Total revolving credit facilities | | $3,300 | $ 3,265 | $ — | $ 35 |

[1] Includes a $50 million lender commitment to the letter of credit sublimits and a $100 million commitment for swingline loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
[2] Includes a $500 million lender commitment to the letter of credit sublimits and a $75 million commitment for swingline loans.

(3) Includes $80 million of letters of credit.

For the year ended December 31, 2018, PG&E Corporation's average outstanding commercial paper balance was $29 million and the maximum outstanding balance during the year was $137 million. For the year ended December 31, 2018, the Utility's average outstanding commercial paper balance was $9 million and the maximum outstanding balance during the year was $205 million. As of December 31, 2018, PG&E Corporation and the Utility each had no commercial paper borrowings outstanding. PG&E Corporation and the Utility do not expect to be able to access the commercial paper market for the duration of the Chapter 11 Cases.

The commencement of the Chapter 11 Cases constituted an event of default or termination event, and caused an automatic and immediate acceleration of 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 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. See Note 15 below for more information.

Revolving Credit Facilities

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022.  As previously disclosed, 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.

Borrowings under each credit agreement (other than swingline loans) previously bore interest based on the borrower’s credit rating and on each borrower’s election of either (1) LIBOR plus an applicable margin or (2) the base rate plus an applicable margin.  The base rate equaled the higher of the following: the administrative agent’s announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin.  The borrower’s credit rating at the time of borrowing determined the applicable rate within the following ranges.  The applicable margin for LIBOR loans ranged between 0.9% and 1.475% under PG&E Corporation’s credit agreement and between 0.8% and 1.275% under the Utility’s credit agreement.  The applicable margin for base rate loans ranged between 0% and 0.475% under PG&E Corporation’s credit agreement and between 0% and 0.275% under the Utility’s credit agreement.  In addition, the facility fee under PG&E Corporation’s and the Utility’s credit agreements ranged between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation’s and the Utility’s revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes.  In addition, the respective revolving credit facilities required that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter.  PG&E Corporation’s revolving credit facility agreement also required that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

Commercial Paper Programs

The borrowings from PG&E Corporation’s and the Utility’s commercial paper programs were used primarily to fund temporary financing needs.  PG&E Corporation and the Utility could issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treated the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper had maturities up to 365 days and ranked equally with PG&E Corporation’s and the Utility’s other unsubordinated and unsecured indebtedness.  Commercial paper notes were sold at an interest rate dictated by the market at the time of issuance.  For 2018, the average yield on outstanding PG&E Corporation and Utility commercial paper was 1.85% and 1.91%, respectively.

Other Short-term Borrowings

In February 2018, the Utility’s $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. In February 2018, the Utility entered into a $250 million floating rate unsecured term loan. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility’s outstanding commercial paper. As a result of the Chapter 11 Cases, repayment of this loan, which was scheduled to mature on February 22, 2019, has been stayed.

As of December 31, 2018, PG&E Corporation and the Utility each had no commercial paper borrowings. PG&E Corporation and the Utility do not expect to be able to access the commercial paper market for the duration of the Chapter 11 Cases.

In November 2018, the Utility's $500 million floating rate unsecured term loan, issued in November 2017, matured and was repaid.

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 520,338,710 shares of common stock outstanding at December 31, 2018. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2018.

During 2018, PG&E Corporation sold no shares of common stock under the February 2017 EDA.

In addition, during 2018, PG&E Corporation sold 5.6 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $199 million. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E common stock to cash.

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 13 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 credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for each company, no amount of PG&E Corporation's retained earnings and $1.4 billion of the Utility's retained earnings was subject to this restriction at December 31, 2018. Additionally, the Utility's net assets, and therefore its ability to pay dividends, are restricted by the CPUC-authorized capital structure, which requires the Utility to maintain, on average, at least 52% equity. Based on the calculation of this ratio, none of the Utility's net assets were restricted at December 31, 2018. Additionally, as a result of this requirement, the Utility's ability to pay dividends in the future could be impacted by future potential liabilities. PG&E Corporation does not expect to pay any cash dividends for the foreseeable future.

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 15,150,532 shares were available for future awards at December 31, 2018.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2018:

| (in millions) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Stock Options | $ 10 | $ — | $— |
| Restricted stock units | 43 | 40 | 53 |
| Performance shares | 36 | 45 | 55 |
| Total compensation expense (pre-tax) | $ 89 | $ 85 | $108 |
| Total compensation expense (after-tax) | $ 63 | $ 50 | $64 |

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 four years of continuous service, subject to accelerated vesting in certain circumstances. As of December 31, 2018, $1.5 million of total unrecognized compensation costs related to nonvested stock options were expected to be recognized over a weighted average period of a year and a half 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 was $10.24 per share in 2018. The significant assumptions used for shares granted in 2018 were:

| | 2018 |
|---|---|
| Expected stock price volatility | 23.00% |
| Expected annual dividend payment | 3.10 % |
| Risk-free interest rate | 2.58 % |
| Expected life (years) | 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, 2018.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2018:

| | Number of Stock Option | Weighted Average Grant-Date Fair Value | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at January 1 | — | N/A | N/A | N/A |
| Granted | 1,571,876 | $ 10.24 | — | — |
| Vested | — | N/A | — | — |
| Forfeited | (49,739 ) | 10.23 | — | — |
| Outstanding at December 31 | 1,522,137 | 10.24 | 9.17 | 0 |
| Expected to vest at December 31 | 1,430,407 | $ 10.24 | 9.17 | 0 |
| Exercisable at December 31 | — | N/A | N/A | N/A |

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 2018, 2017, and 2016 was $40.92, $66.95, and $56.68, respectively. The total fair value of restricted stock units that vested during 2018, 2017, and 2016 was $41 million, $57 million, and $36 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, 2018, $43 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.79 years.

The following table summarizes restricted stock unit activity for 2018:

| | Number of Restricted Stock | Weighted Average Grant- |
|---|---|---|

| | Units | Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,379,235 | $ 60.93 |
| Granted | 1,415,627 | 40.92 |
| Vested | (691,408 ) | 58.78 |
| Forfeited | (123,642 ) | 56.38 |
| Nonvested at December 31 | 1,979,812 | $ 47.66 |

125

Performance Shares

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

Compensation expense attributable to performance share is generally recognized 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 2018, 2017, and 2016 was $36.92, $77.00, and $53.61 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, 2018, $31 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.68 years.

The following table summarizes activity for performance shares in 2018:

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,748,028 | $ 63.40 |
| Granted | 763,392 | 36.92 |
| Vested | (156,747 ) | 56.24 |
| Forfeited [1] | (916,582 ) | 53.68 |
| Nonvested at December 31 | 1,438,091 | $ 56.32 |

[1] Includes performance shares that expired with zero value as performance targets were not met.

NOTE 6: PREFERRED STOCK

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2018 and December 31, 2017, 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, 2018, 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, 2018, 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 2018 (See "Dividends" in Note 5, above). The Utility paid $14 million of dividends on preferred stock in 2017 and 2016.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2018, 2017, and 2016.

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions, except per share amounts) | 2018 | 2017 | 2016 |
| Income available for common shareholders | $(6,851) | $1,646 | $1,393 |
| Weighted average common shares outstanding, basic | 517 | 512 | 499 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | — | 1 | 2 |
| Weighted average common share outstanding, diluted | 517 | 513 | 501 |
| Total earnings per common share, diluted | $(13.25) | $3.21 | $2.78 |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 8: INCOME TAXES

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

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

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

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

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

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| (in millions) | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Current: | | | | | | |
| Federal | $(5) | $(10) | $(105) | $5 | $61 | $(105) |
| State | (8) | 48 | (70) | (7) | 50 | (66) |
| Deferred: | | | | | | |
| Federal | (2,264) | 481 | 218 | (2,278) | 326 | 229 |
| State | (1,009) | 6 | 16 | (1,009) | 4 | 16 |
| Tax credits | (6) | (14) | (4) | (6) | (14) | (4) |
| Income tax provision (benefit) | $(3,292) | $511 | $55 | $(3,295) | $427 | $70 |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| (in millions) | 2018 | 2017 | 2018 | 2017 |
| Deferred income tax assets: | | | | |
| Tax carryforwards | $740 | $830 | $650 | $736 |
| Compensation | 173 | 274 | 121 | 205 |
| Income tax regulatory liability(1) | 79 | 286 | 79 | 286 |
| Wildfire-related Reserve (2) | 3,433 | 34 | 3,433 | 34 |
| Other (3) | 87 | 151 | 93 | 160 |
| Total deferred income tax assets | $4,512 | $1,575 | $4,376 | $1,421 |
| Deferred income tax liabilities: | | | | |
| Property related basis differences | 7,672 | 7,269 | 7,660 | 7,256 |
| Other (4) | 121 | 128 | 121 | 128 |
| Total deferred income tax liabilities | $7,793 | $7,397 | $7,781 | $7,384 |
| Total net deferred income tax liabilities | $3,281 | $5,822 | $3,405 | $5,963 |

(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) Amounts primarily relate to regulatory balancing accounts.

127

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, | | | | | |
| | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Federal statutory income tax rate | 21.0 % | 35.0 % | 35.0 % | 21.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) (1) | 7.9 | 1.5 | (2.5 ) | 7.9 | 1.6 | (2.2 ) |
| Effect of regulatory treatment of fixed asset differences (2) | 3.6 | (16.5) | (23.7) | 3.6 | (16.8) | (23.4) |
| Tax credits | 0.1 | (1.1 ) | (0.8 ) | 0.1 | (1.1 ) | (0.8 ) |
| Benefit of loss carryback | — | — | (1.1 ) | — | — | (1.1 ) |
| Compensation Related (3) | (0.2 ) | (1.0 ) | (0.1 ) | (0.1 ) | (0.9 ) | (0.2 ) |
| Tax Reform Adjustment (4) | 0.1 | 6.8 | — | 0.1 | 3.0 | — |
| Other, net (5) | — | (1.1 ) | (3.0 ) | — | (0.7 ) | (2.5 ) |
| Effective tax rate | 32.5 % | 23.6 % | 3.8 % | 32.6 % | 20.1 % | 4.8 % |

(1) Includes the effect of state flow-through ratemaking treatment. In 2016, amounts reflect a settlement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision (impacting the twelve months ended December 31, 2017), the 2017 GRC decision (impacting the twelve months ended December 31, 2018), and by the 2015 GT&S decision which impacted all periods presented. All amounts are impacted by the level of income before income taxes. The 2014 GRC, 2017 GRC, and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 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 represents the impact of tax audit settlements.

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| (in millions) | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Balance at beginning of year | $349 | $388 | $468 | $349 | $382 | $462 |
| Reductions for tax position taken during a prior year | (27 ) | (71 ) | (77 ) | (27 ) | (71 ) | (77 ) |
| Additions for tax position taken during the current year | 55 | 48 | 56 | 55 | 48 | 56 |
| Settlements | — | (14 ) | (59 ) | — | (8 ) | (59 ) |
| Expiration of statute | — | (3 ) | — | — | (3 ) | — |
| Balance at end of year | $377 | $349 | $388 | $377 | $349 | $382 |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2018 for PG&E Corporation and the Utility was $5 million.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2018, it is reasonably possible that unrecognized tax benefits will decrease by approximately $50 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, 2018, 2017, and 2016, 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. At December 31, 2017, PG&E Corporation and the Utility recorded estimated provisional amounts to reflect the effect of the Tax Act in accordance with Staff Accounting Bulletin No. 118. In 2018, PG&E Corporation and the Utility recorded an approximately $13 million tax benefit to adjust the amount recorded in 2017 for the Tax Act upon obtaining, preparing, and analyzing additional information regarding facts and circumstances that existed as of the enactment date that, if known, would have affected the income tax effects initially reported as provisional amounts.

Although the accounting under ASC 740 to reflect the Tax Act is now complete, 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.

In addition, the Utility filed the estimated revenue impact of the Tax Act with the CPUC and FERC in March and May of 2018, respectively. As of December 31, 2018, the Utility still has not received final regulatory decisions. Depending on the final regulatory outcome, an adjustment may need to be made in the period the final decisions are issued.

Tax settlements

PG&E Corporation's tax returns have been accepted through 2015 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. In February 2017, the Joint Committee of Taxation approved PG&E Corporation's settlement with the IRS related to deductible electric transmission and distribution repairs for the 2011 and 2012 tax years. The agreement provided that the methodology used in determining the deductible amount should be followed for all subsequent periods, absent any material change in facts. In November 2017, PG&E Corporation reached an agreement with the IRS on deductible generation repairs for the 2013 and 2014 tax years.

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, 2018 | Expiration Year |
|---|---|---|
| Federal: | | |
| Net operating loss carryforward | $ 3,880 | 2031 - 2036 |
| Tax credit carryforward | 118 | 2029 - 2037 |
| Charitable contribution loss carryforward | 10 | 2020 |
| | | |
| State: | | |
| Net operating loss carryforward | $ 58 | 2038 |
| Tax credit carryforward | 79 | Various |
| Charitable contribution loss carryforward | 10 | 2020 - 2021 |

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2018 for these tax attributes.

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 during the pendency of the Chapter 11 Cases.

NOTE 9: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

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 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

At December 31, 2018 and 2017, respectively, the volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume | |
|---|---|---|---|
| Underlying Product | Instruments | 2018 | 2017 |
| Natural Gas (1) (MMBtus (2)) | Forwards and Swaps | 177,750,349 | 228,768,745 |
| | Options | 13,735,405 | 60,736,806 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 3,833,490 | 2,872,013 |
| | Congestion Revenue Rights (3) | 340,783,089 | 312,272,177 |

(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, 2018, the Utility’s outstanding derivative balances were as follows:

| (in millions) | Commodity Risk Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
|---|---|---|---|---|
| Current assets – other | $44 | $ (1 ) | $ 89 | $ 132 |
| Other noncurrent assets – other | 165 | — | — | 165 |
| Current liabilities – other | (29 ) | 1 | 7 | (21 ) |
| Noncurrent liabilities – other | (90 ) | — | 2 | (88 ) |
| Total commodity risk | $90 | $ — | $ 98 | $ 188 |

129

At December 31, 2017, the Utility's outstanding derivative balances were as follows:

| (in millions) | Commodity Risk Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
|---|---|---|---|---|
| Current assets – other | $30 | $ (3 ) | $ 10 | $ 37 |
| Other noncurrent assets – other | 103 | (1 ) | — | 102 |
| Current liabilities – other | (47 ) | 3 | 13 | (31 ) |
| Noncurrent liabilities – other | (66 ) | 1 | 8 | (57 ) |
| Total commodity risk | $20 | $ — | $ 31 | $ 51 |

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 certain 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. In January 2019, multiple credit rating agencies downgraded the Utility below investment grade, resulting in the Utility posting $6.2 million to fully collateralize its net liability derivative positions.

NOTE 10: FAIR VALUE MEASUREMENTS

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

- Level 1 – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 – Other inputs that are directly or indirectly observable in the marketplace.

- Level 3 – Unobservable inputs which are supported by little or no market activities.

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

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

| | Fair Value Measurements At December 31, 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 9) | | | | | |
| 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 9) | | | | | |
| 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.

131

| (in millions) | Fair Value Measurements At December 31, 2017 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| Assets: | | | | | |
| Short-term investments | $385 | $— | $— | $ — | $385 |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 23 | — | — | — | 23 |
| Global equity securities | 1,967 | — | — | — | 1,967 |
| Fixed-income securities | 733 | 562 | — | — | 1,295 |
| Assets measured at NAV | — | — | — | — | 18 |
| Total nuclear decommissioning trusts [2] | 2,723 | 562 | — | — | 3,303 |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | — | 3 | 129 | 6 | 138 |
| Gas | — | 1 | — | — | 1 |
| Total price risk management instruments | — | 4 | 129 | 6 | 139 |
| Rabbi trusts | | | | | |
| Fixed-income securities | — | 72 | — | — | 72 |
| Life insurance contracts | — | 71 | — | — | 71 |
| Total rabbi trusts | — | 143 | — | — | 143 |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | — | — | — | 8 |
| Assets measured at NAV | — | — | — | — | 167 |
| Total long-term disability trust | 8 | — | — | — | 175 |
| TOTAL ASSETS | $3,116 | $709 | $129 | $ 6 | $4,145 |
| Liabilities: | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 10 | 15 | 87 | (25 ) | 87 |
| Gas | — | 1 | — | — | 1 |
| TOTAL LIABILITIES | $10 | $16 | $87 | $ (25 ) | $88 |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $440 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the years ended December 31, 2018 and 2017.

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 Sensitivity Analysis

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

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

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

[1] Represents price per megawatt-hour

133

| (in millions) | Fair Value at At December 31, 2017 | | Valuation Technique | Unobservable Input | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | | | Range [1] |
| Congestion revenue rights | $ 129 | $ 24 | Market approach | CRR auction prices | $ (16.03) - 11.99 |
| Power purchase agreements | $ — | $ 63 | Discounted cash flow | Forward prices | $ 18.81 - 38.80 |

[1] Represents price per megawatt-hour

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2018 and 2017, respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Asset (liability) balance as of January 1 | $ 42 | $ 55 |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | 53 | (13 ) |
| Asset (liability) balance as of December 31 | $ 95 | $ 42 |

[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, 2018 and 2017, as they are short-term in nature or have interest rates that reset daily.

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

| | At December 31, | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| (in millions) | Carrying Amount | Level 2 Fair Value | Carrying Amount | Level 2 Fair Value |
| Debt (Note 4) | | | | |
| PG&E Corporation[1] | $350 | $ 350 | $350 | $ 350 |
| Utility | 17,450 | 14,747 | 17,090 | 19,128 |

[1] On April 26, 2018, PG&E Corporation early redeemed its outstanding $350 million principal amount of 2.40% Senior Notes. Also, in April 2018, PG&E
Corporation entered into a $350 million floating rate unsecured term loan. For more information, see Note 4.

134

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, 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 |
| As of December 31, 2017 | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 23 | $ — | $ — | $23 |
| Global equity securities | 524 | 1,463 | (2 ) | 1,985 |
| Fixed-income securities | 1,252 | 51 | (8 ) | 1,295 |
| Total [(1)] | $ 1,799 | $ 1,514 | $ (10 ) | $3,303 |

[(1)] Represents amounts before deducting $408 million and $440 million at December 31, 2018 and 2017, 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, 2018 |
|---|---|
| Less than 1 year | $ 60 |
| 1–5 years | 391 |
| 5–10 years | 341 |
| More than 10 years | 508 |
| Total maturities of fixed-income securities | $ 1,300 |

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

| (in millions) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning investments | $1,412 | $1,291 | $1,295 |
| Gross realized gains on securities | 54 | 53 | 18 |
| Gross realized losses on securities | (24 ) | (11 ) | (26 ) |

NOTE 11: EMPLOYEE BENEFIT PLANS

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

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). 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, $327 million for both 2018 and 2017.

135

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 "Chapter 11 Proceedings" in Note 15 below.)

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 2018 and 2017:

| Pension Plan | | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Change in plan assets: | | |
| Fair value of plan assets at beginning of year | $16,652 | $14,729 |
| Actual return on plan assets | (923) | 2,380 |
| Company contributions | 334 | 335 |
| Benefits and expenses paid | (751) | (792) |
| Fair value of plan assets at end of year | $15,312 | $16,652 |
| | | |
| Change in benefit obligation: | | |
| Benefit obligation at beginning of year | $18,757 | $17,305 |
| Service cost for benefits earned | 514 | 472 |
| Interest cost | 687 | 714 |
| Actuarial (gain) loss | (1,800) | 1,048 |
| Plan amendments | — | 10 |
| Benefits and expenses paid | (751) | (792) |
| Benefit obligation at end of year [1] | $17,407 | $18,757 |
| | | |
| Funded Status: | | |
| Current liability | $(8) | $(7) |
| Noncurrent liability | (2,087) | (2,098) |
| Net liability at end of year | $(2,095) | $(2,105) |

[1] PG&E Corporation's accumulated benefit obligation was $15.8 billion and $16.8 billion at December 31, 2018 and 2017, respectively.

136

Postretirement Benefits Other than Pensions

| (in millions) | 2018 | 2017 |
|---|---|---|
| Change in plan assets: | | |
| Fair value of plan assets at beginning of year | $2,420 | $2,173 |
| Actual return on plan assets | (108) | 298 |
| Company contributions | 31 | 33 |
| Plan participant contribution | 81 | 87 |
| Benefits and expenses paid | (166) | (171) |
| Fair value of plan assets at end of year | $2,258 | $2,420 |
| | | |
| Change in benefit obligation: | | |
| Benefit obligation at beginning of year | $1,897 | $1,877 |
| Service cost for benefits earned | 66 | 59 |
| Interest cost | 69 | 77 |
| Actuarial (gain) loss | (221) | (49) |
| Benefits and expenses paid | (150) | (157) |
| Federal subsidy on benefits paid | 3 | 3 |
| Plan participant contributions | 81 | 87 |
| Benefit obligation at end of year | $1,745 | $1,897 |
| | | |
| Funded Status: (1) | | |
| Noncurrent asset | $545 | $553 |
| Noncurrent liability | (32) | (30) |
| Net asset at end of year | $513 | $523 |

(1) At December 31, 2018 and 2017, 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) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Service cost for benefits earned (1) | $514 | $472 | $453 |
| Interest cost | 687 | 714 | 715 |
| Expected return on plan assets | (1,021) | (770) | (828) |
| Amortization of prior service cost | (6) | (7) | 8 |
| Amortization of net actuarial loss | 5 | 22 | 24 |
| Net periodic benefit cost | 179 | 431 | 372 |
| Less: transfer to regulatory account (2) | 157 | (92) | (34) |
| Total expense recognized | $336 | $339 | $338 |

(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) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Service cost for benefits earned [1] | $66 | $59 | $52 |
| Interest cost | 69 | 77 | 76 |
| Expected return on plan assets | (130) | (97 ) | (107) |
| Amortization of prior service cost | 14 | 15 | 15 |
| Amortization of net actuarial loss | (5 ) | 4 | 4 |
| Net periodic benefit cost | $14 | $58 | $40 |

[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 2019 are as follows:

| (in millions) | Pension Plan | PBOP Plans |
|---|---|---|
| Unrecognized prior service cost | $ (6 ) | $ 14 |
| Unrecognized net loss | 3 | (3 ) |
| Total | $ (3 ) | $ 11 |

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 December 31, | | | PBOP Plans December 31, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Discount rate | 4.35% | 3.64% | 4.11% | 4.29 - 4.37% | 3.60 - 3.67 % | 4.05 - 4.19 % |

| | | | | | | |
|---|---|---|---|---|---|---|
| Rate of future compensation increases | 3.90% | 3.90% | 4.00% | — | — | — |
| Expected return on plan assets | 6.00% | 6.20% | 5.30% | 3.60 - 6.80% | 3.30 - 7.10% | 2.80 - 6.00% |

138

The assumed health care cost trend rate as of December 31, 2018 was 6.5%, 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 | $ 112 | $ (113 ) |
| Effect on service and interest cost | 9 | (10 ) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.0% compares to a ten-year actual return of 10.0%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 1,101 Aa-grade non-callable bonds at December 31, 2018. 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 | | |
|---|---|---|---|---|---|---|
| | 2019 | 2018 | 2017 | 2019 | 2018 | 2017 |
| Global equity securities | 29 % | 29 % | 27 % | 33 % | 33 % | 32 % |

| | | | | | | |
|---|---|---|---|---|---|---|
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 3 % |
| Real assets | 8 % | 8 % | 10 % | 6 % | 6 % | 7 % |
| Fixed-income securities | 58 % | 58 % | 58 % | 58 % | 58 % | 58 % |
| Total | 100 % | 100 % | 100 % | 100 % | 100 % | 100 % |

139

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, 2018 and 2017.

| | Fair Value Measurements At December 31, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | | | | 2017 | | | |
| (in millions) | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Pension Plan: | | | | | | | | |
| Short-term investments | $333 | $22 | $ — | $355 | $287 | $424 | $ — | $711 |
| Global equity securities | 1,145 | — | — | 1,145 | 1,292 | — | — | 1,292 |
| Real assets | 461 | — | — | 461 | 499 | — | — | 499 |
| Fixed-income securities | 1,897 | 5,216 | 8 | 7,121 | 1,916 | 5,520 | 4 | 7,440 |
| Assets measured at NAV | — | — | — | 6,202 | — | — | — | 6,818 |
| Total | $3,836 | $5,238 | $ 8 | $15,284 | $3,994 | $5,944 | $ 4 | $16,760 |
| PBOP Plans: | | | | | | | | |
| Short-term investments | $33 | $— | $ — | $33 | $31 | $— | $ — | $31 |
| Global equity securities | 115 | — | — | 115 | 141 | — | — | 141 |
| Real assets | 50 | — | — | 50 | 55 | — | — | 55 |
| Fixed-income securities | 153 | 857 | — | 1,010 | 163 | 757 | — | 920 |
| Assets measured at NAV | — | — | — | 1,056 | — | — | — | 1,281 |
| Total | $351 | $857 | $ — | $2,264 | $390 | $757 | $ — | $2,428 |
| Total plan assets at fair value | | | | $17,548 | | | | $19,188 |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net liabilities of $22 million and other net assets of $116 million at December 31, 2018 and 2017, 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

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2018 and 2017.

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, 2018 and 2017:

| (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 | |

| (in millions) | | |
|---|---|---|
| For the year ended December 31, 2017 | Fixed-Income | |
| Balance at beginning of year | $ | 5 |

| | |
|---|---|
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | (1 ) |
| Relating to assets sold during the period | — |
| Purchases, issuances, sales, and settlements: | |
| Purchases | 3 |
| Settlements | (3 ) |
| Balance at end of year | $ 4 |

141

There were no material transfers out of Level 3 in 2018 and 2017.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $31 million to the other benefit plans in 2018. 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 2018. 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 $24 million to the pension plan and other postretirement benefit plans, respectively, for 2019.

Benefits Payments and Receipts

As of December 31, 2018, 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 |
|---|---|---|---|
| 2019 | 778 | 88 | (8 ) |
| 2020 | 855 | 91 | (9 ) |
| 2021 | 891 | 94 | (9 ) |
| 2022 | 925 | 99 | (3 ) |
| 2023 | 957 | 102 | (3 ) |
| Thereafter in the succeeding five years | 5,136 | 507 | (12 ) |

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 $105 million, $103 million, and $97 million in 2018, 2017, and 2016, respectively.

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

NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 2018 | 2017 | 2016 |
| Utility revenues from: | | | |
| Administrative services provided to PG&E Corporation | $4 | $ 8 | $ 7 |
| Utility expenses from: | | | |
| Administrative services received from PG&E Corporation | $94 | $ 65 | $ 74 |
| Utility employee benefit due to PG&E Corporation | 76 | 73 | 91 |

At December 31, 2018 and 2017, the Utility had receivables of $33 million and $20 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 $38 million and $22 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 13: 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.

Wildfire-Related Claims

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.

For the years ended December 31, 2018, 2017 and 2016, the Utility’s Consolidated Income Statements include estimated losses offset by insurance recoveries as follows:

| (in millions) | Year Ended December 31, 2018 | 2017 | 2016 |
|---|---|---|---|
| 2015 Butte fire | | | |
| Third-Party Claims | $— | $350 | $750 |
| Insurance recoveries | (7) | (350) | (625) |
| Total 2015 Butte fire | (7) | — | 125 |
| 2017 Northern California wildfires | | | |
| Third-Party Claims | 3,500 | — | — |
| Insurance recoveries | (842) | — | — |
| Total 2017 Northern California wildfires | 2,658 | — | — |
| 2018 Camp fire | | | |
| Third-Party Claims | 10,500 | — | — |
| Insurance recoveries | (1,380) | — | — |
| Total 2018 Camp fire | 9,120 | — | — |
| Total wildfire-related claims, net of insurance recoveries | $11,771 | $— | $125 |

In addition to the amounts shown in the table above, during the year ended December 31, 2018, the Utility incurred $245 million of legal and other costs related to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire.

At December 31, 2018 and 2017, the Utility's Consolidated Balance Sheets include estimated liabilities as follows:

| (in millions) | Balance At December 31, 2018 | December 31, 2017 |
|---|---|---|
| 2015 Butte fire | $226 | $ 561 |
| 2017 Northern California wildfires | 3,500 | — |
| 2018 Camp fire | 10,500 | — |
| Total wildfire-related claims | $14,226 | $ 561 |

2018 Camp Fire Background

On November 8, 2018, 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 January 4, 2019, (the “Cal Fire website”), indicated that the 2018 Camp fire consumed 153,336 acres. On the Cal Fire website, Cal Fire reported 86 fatalities and the destruction of 13,972 residences, 528 commercial structures and 4,293 other buildings resulting from the 2018 Camp fire. On February 7, 2019, the Butte County Sheriff's Office reported that the number of fatalities resulting from the 2018 Camp fire had been reduced from 86 to 85.

Although the cause of the 2018 Camp fire is still under investigation, based on the information currently known to PG&E Corporation and the Utility and reported to the CPUC and other agencies, including the facts described below, PG&E Corporation and the Utility believe it is probable that the Utility's equipment will be determined to be an ignition point of the 2018 Camp fire.

The Utility submitted two Electric Incident Reports (the "EIRs") to the CPUC: one on November 8, 2018 and one on November 16, 2018. On December 11, 2018, the Utility publicly released a letter to the CPUC supplementing the EIRs (the "20-Day Electric Incident Report"), which stated:

- On Cal Fire's website, Cal Fire has identified coordinates for the 2018 Camp fire near Tower :27/222 on the Utility's Caribou-Palermo 115 kV Transmission Line and has identified the start time of the 2018 Camp fire as 6:33 a.m. on November 8, 2018.

- On November 8, 2018, at approximately 6:15 a.m., the Utility's Caribou-Palermo 115kV Transmission Line relayed and deenergized. At approximately 6:30 a.m. that day, a Utility employee observed fire in the vicinity of Tower :27/222, and this observation was reported to 911 by Utility employees. In the afternoon of November 8, the Utility observed damage on the line at Tower :27/222. Specifically, an aerial patrol identified that a suspension insulator supporting a transposition jumper had separated from an arm on Tower :27/222.

- On November 14, 2018, the Utility observed a broken C-hook attached to the separated suspension insulator that had connected the suspension insulator to a tower arm, along with wear at the connection point. In addition, the Utility observed a flash mark on Tower :27/222 near where the transposition jumper was suspended and damage to the transposition jumper and suspension insulator.

- In addition to the events on the Caribou-Palermo 115kV Transmission Line, on November 8, 2018, at approximately 6:45 a.m., the Utility's Big Bend 1101 12 kV Circuit experienced an outage. On November 9, 2018, a Utility employee on patrol arrived at the location of the pole with Line Recloser ("LR") 1704 on the Big Bend 1101 Circuit and observed that the pole and other equipment were on the ground with bullets and bullet holes at the break point of the pole and on the equipment. On November 12, 2018, a Utility employee was patrolling Concow Road north of LR 1704 when he observed wires down and damaged and downed poles at the intersection of Concow Road and Rim Road. At this location, the employee observed several snapped trees, with some on top of the downed wires.

The information contained in the EIRs and the 20-Day Electric Incident Report is factual and preliminary and does not reflect a determination of the causes of the 2018 Camp fire. These incidents remain under investigation by Cal Fire and the CPUC. With respect to the potential ignition point on the Utility's Big Bend 1101 12 kV Circuit, although Cal Fire has identified this location as a potential ignition point, based on the condition of the site, PG&E Corporation and the Utility have not been able to determine whether the Big Bend 1101 12 kV Circuit may be a probable ignition point for the 2018 Camp fire. Neither Cal Fire nor the CPUC has publicly issued any news releases or other determinations for the 2018 Camp fire. The timing and outcome of the investigations are uncertain. PG&E Corporation and the Utility are cooperating with Cal Fire and the CPUC.

Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating the fire. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

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 issued its determination on the causes of 19 of the 2017 Northern California wildfires, and alleged that all of these fires, with the exception of the Tubbs fire, involved the Utility's equipment. The remaining wildfires remain under Cal Fire's investigation, including the possible role of the Utility's power lines and other facilities.

During the second quarter of 2018, Cal Fire issued news releases announcing its determination on the causes of 16 of the 2017 Northern California wildfires (the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires, located in Mendocino, Lake, Butte, Sonoma, Humboldt, Nevada and Napa counties). According to the Cal Fire news releases, the first four fires “were caused by trees coming into contact with power lines” and the remaining 12 fires “were caused by electric power and distribution lines, conductors and the failure of power poles.” Cal Fire has not yet released its investigation reports related to the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires and stated in its news releases that these investigations have been referred to the appropriate county District Attorney’s offices for review “due to evidence of alleged violations of state law.” The Butte County District Attorney's office has entered into a settlement agreement with the Utility, resolving the Honey, Cherokee and LaPorte fire allegations without criminal or civil charges. The timing and outcome for resolution of the remaining referrals are uncertain.

Also during the second quarter of 2018, Cal Fire released its investigation reports related to the Redwood, Cherokee, 37, Nuns and La Porte fires. Cal Fire did not refer these fires to District Attorney offices for investigation.

On October 9, 2018, Cal Fire issued a news release announcing the results of its investigation into the Cascade fire, located in Yuba County, concluding that the Cascade fire “was started by sagging power lines coming into contact during heavy winds” and that “the power line in question was owned by Pacific Gas and Electric Company.” On October 10, 2018, Cal Fire released its investigation report related to the Cascade fire.

On January 24, 2019, Cal Fire issued a news release and its investigation report into the cause of the Tubbs fire. Cal Fire has determined that the Tubbs fire was caused by a private electrical system adjacent to a residential structure.

Cal Fire has not publicly issued any news releases or other determinations for the Maacama, Pressley and Point wildfires. The timing and outcome of the Cal Fire investigation into these fires is uncertain.

Further, the SED is conducting investigations to assess the compliance of electric and communication companies’ facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

The Utility has submitted 23 electric incident reports to the CPUC associated with the 2017 Northern California wildfires where Cal Fire or the Utility has identified a site as potentially involving the Utility’s facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary and does not reflect a determination of the causes of the fires.

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.)

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 or penalties if the CPUC or any law enforcement agency brought an enforcement action, including a criminal proceeding, and determined that the Utility failed to comply with applicable laws and regulations.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 100 complaints on behalf of at least 4,200 plaintiffs related to the 2018 Camp fire, nine of which seek 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, includes claims under multiple theories of liability, including 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 assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2018 Camp fire. The plaintiffs seek 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. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 750 complaints on behalf of at least 3,800 plaintiffs related to the 2017 Northern California wildfires, five of which seek to be certified as class actions. These cases have been 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, includes claims under multiple theories of liability, including 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 assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2017 Northern California wildfires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees and other damages. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Insurance carriers who have made payments to their insureds for property damage arising out of the 2017 Northern California wildfires have filed 48 subrogation complaints in the San Francisco 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, insurance carriers have filed 37 similar subrogation complaints with respect to the 2018 Camp fire in the Sacramento County Superior Court. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Various government entities, including Yuba, Nevada, Lake, Mendocino, Napa and Sonoma Counties and the Cities of Santa Rosa and Clearlake, also have 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 include, 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, and PG&E Corporation and the Utility expect additional similar claims to be made by other government entities. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

On March 16, 2018, PG&E Corporation and the Utility filed a demurrer to the inverse condemnation cause of action in the 2017 Northern California wildfires litigation. On May 21, 2018, the court overruled the motion. On July 20, 2018, PG&E Corporation and the Utility filed a writ in the Court of Appeal requesting appellate review of the trial court's decision, which was denied on September 17, 2018. On September 27, 2018, PG&E Corporation and the Utility filed a petition for review to the California Supreme Court. On November 14, 2018, the California Supreme Court denied PG&E Corporation's and the Utility's petition for review.

PG&E Corporation and the Utility expect to be the subject of numerous additional claims in connection with 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.

PG&E Corporation and the Utility also are the subject of criminal investigations or other actions by the county District Attorneys to whom Cal Fire has referred its investigations into the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires. Although the Honey fire was referred to the Butte County District Attorney’s Office, 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 were not referred). The settlement provides for funding by the Utility for at least four years of an enhanced fire prevention and communication program, in the amount of up to $1.5 million, not recoverable in rates. On October 9, 2018, the District Attorney of Yuba County announced his decision not to pursue criminal charges at such time against PG&E Corporation or the Utility pertaining to the Cascade fire. The Office of the District Attorney of Yuba County also indicated that it “reserves 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.”

Also in October 2018, the Utility and the Sonoma, Napa, Lake, Humboldt and Nevada County District Attorneys entered into agreements under which the Utility agreed to waive any applicable statutes of limitation related to the 2017 Northern California wildfires that started in these counties for a period of six months, until April 8, 2019. PG&E Corporation and the Utility anticipate further discussions with the District Attorneys in these counties relating to the 2017 Northern California wildfires and whether any criminal or civil charges should be brought. 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. Additional investigations and other actions may arise out of the other 2017 Northern California wildfires and the 2018 Camp fire. Such 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.

PG&E Corporation and the Utility are continuing to review the evidence concerning the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility have not yet had access to all of the evidence collected by Cal Fire as part of its investigations or to the many investigation reports prepared by Cal Fire. PG&E Corporation and the Utility and plaintiffs are in discussions with Cal Fire about access to the evidence and the remaining reports. No schedule on gaining access has been set.

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 resolved through the Chapter 11 process, regulatory proceedings and any potential enforcement proceedings, all of which could take a number of years to resolve. The timing and outcome of these and other potential proceedings are uncertain.

Potential Losses in Connection with the 2018 Camp Fire and 2017 Northern California Wildfires

On January 28, 2019, the California Department of Insurance issued a news release announcing an update on property losses in connection with the 2018 wildfires in Southern California (which are not in the Utility’s service territory) and the 2018 Camp fire, stating that, as of such date, “more than $11.4 billion in insured losses have been reported from the November 2018 fires,” of which approximately $8.4 billion relates to statewide claims from the 2018 Camp fire. On September 6, 2018, the California Department of Insurance issued a news release announcing that insurers have received nearly 55,000 insurance claims totaling more than $12.28 billion in losses, of which approximately $10 billion relates to statewide claims from the 2017 Northern California wildfires.

The dollar amounts announced by the California Department of Insurance represent an aggregate amount of approximately $18.4 billion of insurance claims made as of the above dates related to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility expect that additional claims have been submitted and will continue to be submitted to insurers, particularly with respect to the 2018 Camp fire. These claims reflect insured property losses only. The $18.4 billion of insurance claims made as of the above dates does not account for uninsured or underinsured property losses, interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses or other costs, such as potential punitive damages, fines or penalties, or losses related to claims that have not manifested yet ("future claims"), each of which could be significant. The scope of all claims related to the 2018 Camp fire and 2017 Northern California wildfires is not known at this time because of the applicable statutes of limitations under California law.

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, 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. Among other things, it is uncertain at this time as to the number of wildfire-related claims that will be filed in the Chapter 11 Cases, the number of current and future claims that will be allowed by the Bankruptcy Court, how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed, and the impact that historical settlement values for wildfire claims may have on the estimation of wildfire liability in the Chapter 11 Cases. If PG&E Corporation and the Utility were to be found liable for certain or all of the costs, expenses and other losses described above with respect to the 2018 Camp fire and 2017 Northern California wildfires, the amount of such liability could exceed $30 billion, which amount does not include potential punitive damages, fines and penalties or damages related to future claims. This estimate is based on a wide variety of data and other information available to PG&E Corporation and the Utility and their advisors, including various precedents involving similar claims, and accounts for property losses (including insured, uninsured and underinsured property losses), interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses and certain other costs. This estimate is not intended to provide an upper end of the range of potential liability arising from the 2018 Camp fire and 2017 Northern California wildfires. In certain circumstances, PG&E Corporation's and the Utility's liability could be substantially greater than such amount.

If PG&E Corporation and the Utility were to be found liable for any punitive damages or 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. Such 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.

2018 Camp Fire and 2017 Northern California Wildfires Accounting Charge

Following accounting rules, PG&E Corporation and the Utility record a liability when a loss is probable and reasonably estimable. In accordance with U.S. generally accepted accounting principles, 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 is the amount within the range that is a better estimate than any other amount 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.

2018 Camp Fire

In light of the current state of the law and the information currently available to the Utility, including, among other things, the facts described in the EIRs and the 20-Day Electric Incident Report, 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 accordingly PG&E Corporation and the Utility recorded a charge in the amount of $10.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses, and is subject to change based on additional information.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2018 Camp fire and 2017 Northern California wildfires will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because 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 and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

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 factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2018 Camp fire may change, which could result in material increases to the loss accrued.

The $10.5 billion charge 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.

2017 Northern California Wildfires

In light of the current state of the law on inverse condemnation and the information currently available to the Utility, including, among other things, the Cal Fire determinations of cause as stated in Cal Fire's press releases and their released reports, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with 17 of the 2017 Northern California wildfires referred to as the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket, Atlas, Cascade, Point and Sonoma/Napa merged fires (which include the Nuns, Norrbom, Adobe, Partrick and Pythian fires). Accordingly, PG&E Corporation and the Utility recorded a charge in the amount of $2.5 billion during the quarter ended June 30, 2018 and a charge in the amount of $1.0 billion during the quarter ended December 31, 2018, for a total charge in the amount of $3.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses and is subject to change based on additional information. The additional charge recorded in the quarter ended December 31, 2018 resulted from additional information obtained by the Utility during that period about the fires.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2017 Northern California wildfires and the 2018 Camp fire will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because 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 and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

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 factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2017 Northern California wildfires may change, which could result in material increases to the loss accrued.

The $3.5 billion charge 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 $3.5 billion charge also does not include any amounts in connection with the 37, Tubbs, Maacama and Pressley fires because at this time PG&E Corporation and the Utility have not concluded that a loss arising from those fires is probable. However, in the future it is possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability at that time, the amount of which could be significant.

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 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.

Insurance

PG&E Corporation and the Utility had $842 million of insurance coverage for liabilities, including wildfire events, for the period from August 1, 2017 through July 31, 2018, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. During the third quarter of 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. PG&E Corporation and the Utility expect to face increasing difficulty securing liability insurance in future years due to availability and to face significantly increased insurance costs.

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, 2018, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $842 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. The amount of the receivable is subject to change based on additional information. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future.

If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, or if insurance is otherwise unavailable, 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 2017 Northern California wildfires will greatly exceed their available insurance.

The following table presents changes in the insurance receivable for the year ended December 31, 2018. The balance for insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| (in millions) | Insurance Receivable |
|---|---|
| 2018 Camp fire | |
| Accrued insurance recoveries | $ 1,380 |
| Reimbursements | — |
| Balance at December 31, 2018 | $ 1,380 |

2017 Northern California wildfires

| | |
|---|---|
| Accrued insurance recoveries | $ 842 |
| Reimbursements | (13 ) |
| Balance at December 31, 2018 | $ 829 |

151

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 customer harm threshold, 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 (the "Customer Harm Threshold"). 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 Customer Harm Threshold. 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.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Following the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis unless the CPUC alters the position expressed in the OIR.

On February 11, 2019, PG&E Corporation and the Utility filed opening comments in response to the OIR in which they argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt PG&E Corporation and the Utility can raise. Based on assumptions set forth in the comments, PG&E Corporation and the Utility indicated that they could borrow up to approximately $3 billion to fund wildfire claims costs as part of a plan of reorganization.

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.

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. The hearing on this motion, previously set for January 31, 2019, was moved by stipulation of the parties and order of the court to March 7, 2019.

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. 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. The court scheduled an initial case management conference for March 21, 2019.

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. 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. The court has not yet acted on the plaintiff’s response.

Wildfire-Related Securities Class Action Litigation

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 complaint names as defendants certain current and former officers and directors, as well as the underwriters of 4 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 federal Securities Act of 1933, and seeks unspecified monetary relief, attorneys’ fees and other costs, and injunctive relief. If necessary, PG&E Corporation and the Utility intend to file a complaint in Bankruptcy Court against the plaintiffs seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer and director defendants.

Clean-up and Repair Costs

The Utility incurred costs of $354 million for clean-up and repair of the Utility’s facilities (including $183 million in capital expenditures) through December 31, 2018, in connection with the 2018 Camp fire. The Utility also incurred costs of $327 million for clean-up and repair of the Utility’s facilities (including $157 million in capital expenditures) through December 31, 2018, 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, 2018, the CEMA balance related to the 2017 Northern California wildfires was $82 million and is 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 at December 31, 2018.

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 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.

2015 Butte Fire

In September 2015, a wildfire (the “2015 Butte fire”) ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the 2015 Butte fire. According to Cal Fire’s report, the 2015 Butte fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire’s report concluded that the 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.

154

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 31, 2019, 95 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,900 individual plaintiffs representing approximately 2,000 households and their insurance companies. These complaints are part of, or were in the process of being added to, the coordinated proceeding. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. 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 April 28, 2017, the Utility moved for summary adjudication on plaintiffs' claims for punitive damages. The court denied the Utility's motion and the Utility filed a writ with the Court of Appeal of the State of California, Third Appellate District. The writ was granted on July 2, 2018, directing the trial court to enter summary adjudication in favor of the Utility and to deny plaintiffs' claim for punitive damages under California Civil Code Section 3294. Plaintiffs sought rehearing and asked the California Supreme Court to review the Court of Appeal's decision. Both requests were denied. Neither the trial nor appellate courts originally addressed whether plaintiffs can seek punitive damages at trial under Public Utilities Code Section 2106. However, the trial court, in November 2018, denied a motion filed by the Utility that would have confirmed that punitive damages under Public Utilities Code Section 2106 are unavailable. The Utility believes a loss related to punitive damages is unlikely, but possible.

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 applies to the Utility with respect to the 2015 Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding at the time of the ruling, others could make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases.

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 court determined that it is bound by earlier holdings of two appellate courts decisions, Barham and Pacific Bell. Further, the court stated that the Utility's constitutional arguments should be made to the appellate courts and suggested that, to the extent the Utility raises the public policy implications of the November 30, 2017 CPUC decision in the San Diego Gas & Electric Company cost recovery proceeding, these arguments should be addressed to the Legislature or CPUC. The Utility filed a writ with the Court of Appeal seeking immediate review of the court's decision. On June 18, 2018, after the writ was summarily denied, the Utility filed a Petition for Review with the California Supreme Court, which also was denied. On September 6, 2018, the court set a trial for some individual plaintiffs to begin on April 1, 2019. 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 California Office of Emergency Services (the “OES”), the County of Calaveras, and five smaller public entities (three fire districts, one water district and the California Department of Veterans Affairs) have brought suit or indicated that they intend to do so. The five smaller public entities filed their complaints in August 2018 and September 2018. They have been added to the coordinated proceedings. The Utility has settled the claims of the three fire protection districts.

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 on the theory that the Utility and its vegetation management contractors were negligent, or violated the law, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Trees, Inc., one of the Utility's vegetation contractors. Cal Fire had requested that a trial of its claims be set in 2019, following any trial of the claims of the individual plaintiffs. On October 19, 2018, the Utility filed a motion for summary judgment arguing that Cal Fire cannot recover any fire suppression costs under the Third District Court of Appeal's decision in Dep't of Forestry & Fire Prot. v. Howell (2017) 18 Cal. App. 5th 154. The hearing on that motion was set for January 31, 2019, but the hearing and Cal Fire's case against the Utility are 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 to recover damages and other costs, based on the doctrine of inverse condemnation and negligence theory of liability. The County also sought punitive damages. On March 2, 2018, the County served a mediation demand seeking in excess of $167 million, having previously indicated that it intended to bring an approximately $85 million claim against the Utility. This claim included costs that the County of Calaveras allegedly incurred or expected to incur for infrastructure damage, erosion control, and other costs. The Utility and the County of Calaveras settled the County's claims in November 2018 for $25.4 million.

Further, in May 2017, the OES indicated that it intended to bring a claim against the Utility that it estimated to be approximately $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the 2015 Butte fire. The Utility has not received any information or documentation from OES since its May 2017 statement. In June 2017, the Utility entered into an agreement with the OES that extends their 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.

Estimated Losses from Third-Party Claims

In connection with the 2015 Butte fire, the Utility may be liable for property damages, business interruption, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation.

In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility is found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court would agree with the Utility.

The Utility's assessment of the estimated loss related to the 2015 Butte fire is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages.

The Utility has determined that it is probable that it will incur a loss of $1.1 billion in connection with the 2015 Butte fire. While this amount includes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate any liability it may have for that additional claim.

The process for estimating costs associated with claims relating to the 2015 Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, management estimates and assumptions regarding the financial impact of the 2015 Butte fire may result in material increases to the loss accrued.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Wildfire-related claims in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| Loss Accrual (in millions) | |
|---|---|
| Balance at December 31, 2015 | $— |
| Accrued losses | 750 |
| Payments [1] | (60 ) |
| Balance at December 31, 2016 | 690 |
| Accrued losses | 350 |
| Payments [1] | (479 ) |
| Balance at December 31, 2017 | 561 |
| Accrued losses | — |
| Payments [1] | (335 ) |
| Balance at December 31, 2018 | $226 |

[1] As of December 31, 2018, the Utility has paid $874 million of the $904 million in settlements to date in connection with the 2015 Butte fire.

If the Utility records losses in connection with claims relating to the 2015 Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the reporting periods during which additional charges are recorded.

Loss Recoveries

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, 2018, 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 (excluded from the table below), including $7 million received in the year ended December 31, 2018. Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| Insurance Receivable (in millions) | |
|---|---|
| Balance at December 31, 2015 | $— |
| Accrued insurance recoveries | 625 |
| Reimbursements | (50 ) |
| Balance at December 31, 2016 | 575 |
| Accrued insurance recoveries | 297 |
| Reimbursements | (276) |
| Balance at December 31, 2017 | 596 |
| Accrued insurance recoveries | — |
| Reimbursements | (511) |

| | |
|---|---|
| Balance at December 31, 2018 | $85 |

In January and February 2019, the Utility received an additional $25 million in insurance reimbursements.

157

NOTE 14: 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

In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations.  It is uncertain whether any charges will be brought against the Utility. Such 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.

CPUC and FERC Matters

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 (the "OII") to assess the Utility's practices and procedures related to the locating and marking of natural gas facilities. The OII directs the Utility to show cause as to why the Commission should not find violations in this matter, and why the Commission should not impose penalties, and/or any other forms of relief, if any violations are found. The Utility also is 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 cites 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 the Utility's late tickets counts, 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.

The CPUC indicates that it has not concluded that the Utility has violated the law in any instance pertaining to late tickets, locating and marking, or any matter related to either, or to any other matter raised in this OII. However, if violations are found, the CPUC will consider what monetary fines and other remedies are appropriate, will review the duration of violations and, if supported by the evidence, it will consider ordering daily fines.

On January 14, 2019, the Utility submitted responses to preliminary questions raised in the OII and separately filed an affidavit regarding the safety of the locate and mark program. On March 14, 2019, as directed by the CPUC, the Utility expects to submit a report that addresses the SED report and respond to the order to show cause. A schedule for future proceedings is expected to be established at an April 5, 2019 pre-hearing conference.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties, including fines or other remedies, on the Utility. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining penalties. The Utility is unable to predict the timing and outcome of this proceeding.

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.

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have occurred or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.

On April 26, 2018, the CPUC approved the revised proposed decision issued on April 3, 2018, adopting 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, Cal PA, the SED, and TURN.

The decision results 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, 2018, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $32 million accrual for a portion of the 2018 GT&S revenue requirement reduction. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

The CPUC also ordered a second phase in this proceeding to determine if any of the additional communications that the Utility reported to the CPUC on September 21, 2017, violate the CPUC ex parte rules. On May 22, 2018, the assigned ALJ issued a ruling requiring the parties to meet and confer to determine if an agreement can be reached on the issues identified by the ALJ. On September 17, 2018, the parties submitted a joint status report indicating a settlement in principle could not be reached. The ALJ will hold a prehearing conference with the parties to determine if evidentiary hearings are required. The Utility is unable to predict the timing and outcome of the second phase in this proceeding.

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.

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 will go 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 by mid-2019, however, that decision will likely be the subject of requests for rehearing and appeal. The Utility is unable to predict the timing of when a final decision will be issued. On September 21, 2018, the Utility filed an all-party settlement with 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 in the TO18 final decision. The Utility is unable to predict the timing or outcome of FERC's decisions in these proceedings.

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 in Note 13 and above under "Enforcement and Litigation Matters") totaled $98 million at December 31, 2018 and $86 million at December 31, 2017. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material effect on their financial condition, results of operations, liquidity, and cash flows.

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. The decision also established various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million for 2011 through 2014 capital expenditures in excess of adopted amounts and $44 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. 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.

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, 2018 | December 31, 2017 |
|---|---|---|
| Topock natural gas compressor station | $369 | $ 334 |
| Hinkley natural gas compressor station | 146 | 147 |
| Former manufactured gas plant sites owned by the Utility or third parties [1] | 520 | 320 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites [2] | 111 | 115 |
| Fossil fuel-fired generation facilities and sites [3] | 137 | 123 |
| Total environmental remediation liability | $1,283 | $ 1,039 |

[1] Primarily driven by the following sites: Vallejo, San Francisco East Harbor, Napa, 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, 2018, 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, 2018, the Utility expected to recover $930 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.

161

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 $303 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. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $141 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 undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $518 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 $135 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 $105 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 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. Various coverage limitations applicable to different insurance layers could result in substantial uninsured costs in the future depending on the amount and type of damages.

PG&E Corporation's and the Utility's cost of obtaining wildfire insurance coverage has increased to $360 million, compared to the adopted approximately $50 million that the Utility is currently recovering through rates through December 31, 2019. The Utility intends to seek recovery for the full amount of premium costs paid in excess of the amount the Utility currently is recovering from customers through the end of the current GRC period, which ends on December 31, 2019.

Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities.  NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3.  NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon.  Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants.  Certain acts of terrorism may be "certified" by the Secretary of the Treasury.  If damages are caused by certified acts of terrorism, NEIL can obtain 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 December 31, 2018, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $47 million. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $3 million, as of December 31, 2018.

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 $14.1 billion. The Utility purchased the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $14.1 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 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 $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.

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.

At December 31, 2018 and December 31, 2017, respectively, the Consolidated Balance Sheets reflected $220 million and $243 million in net claims within Disputed claims and customer refunds related to the 2001 Chapter 11 proceeding. 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, are expected to be determined through the proceedings of the Chapter 11 Cases.

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, 2018:

| | Power Purchase Agreements | | | | | |
|---|---|---|---|---|---|---|
| (in millions) | Renewable Energy | Conventional Energy | Other | Natural Gas | Nuclear Fuel | Total |
| 2019 | $2,221 | $ 642 | $108 | $412 | $ 108 | $3,491 |
| 2020 | 2,183 | 639 | 83 | 153 | 151 | 3,209 |
| 2021 | 2,174 | 582 | 65 | 93 | 64 | 2,978 |
| 2022 | 1,984 | 511 | 61 | 93 | 54 | 2,703 |
| 2023 | 1,914 | 223 | 61 | 93 | 49 | 2,340 |
| Thereafter | 24,217 | 435 | 162 | 264 | 47 | 25,125 |
| Total purchase commitments | $34,693 | $ 3,032 | $540 | $1,108 | $ 473 | $39,846 |

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. (For more information see "Chapter 11 Proceedings" in Note 15 below.)

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, 2018, 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, 2018, 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. Two of these agreements are treated as capital leases. At December 31, 2018 and 2017, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $11 million and $18 million including accumulated amortization of $8 million and $143 million, respectively. The present value of the future minimum lease payments due under these agreements included $2 million and $11 million in Current Liabilities and $9 million and $7 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2018, 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 $3.1 billion in 2018, $3.3 billion in 2017, and $3.5 billion in 2016.

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 $0.6 billion in 2018, $0.9 billion in 2017, and $0.7 billion in 2016.

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 $73 million in 2018, $83 million in 2017, and $100 million in 2016.

165

Other Commitments

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2019 and 2052. At December 31, 2018, the future minimum payments related to these commitments were as follows:

| (in millions) | Operating Leases |
|---|---|
| 2019 | $ 44 |
| 2020 | 41 |
| 2021 | 36 |
| 2022 | 28 |
| 2023 | 19 |
| Thereafter | 121 |
| Total minimum lease payments | $ 289 |

Payments for other commitments related to operating leases amounted to $43 million in 2018, $45 million in 2017, and $43 million in 2016. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

NOTE 15: SUBSEQUENT EVENTS

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).

PG&E Corporation and the Utility continue to operate their businesses as debtors 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. As debtors in possession, PG&E Corporation and the Utility are authorized to continue to operate as ongoing businesses, and may pay all debts and honor all obligations arising in the ordinary course of their businesses after the Petition Date. However, PG&E Corporation and the Utility may not pay third-party claims or creditors on account of obligations arising before the Petition Date or engage in transactions outside the ordinary course of business without approval 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 13 above), are subject to an automatic stay. Absent an order of the Bankruptcy Court providing otherwise, substantially all pre-petition liabilities will be administered under a Chapter 11 plan of reorganization to be voted upon by creditors and other stakeholders, and approved by the Bankruptcy Court. However, under the Bankruptcy Code, regulatory or criminal proceedings are generally not subject to an automatic stay, and PG&E Corporation and the Utility expect these proceedings to continue during the pendency of the Chapter 11 Cases.

To assure ordinary course operations, on January 31, 2019, PG&E Corporation and the Utility received interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions that authorize them to maintain their existing cash management system, to continue wage and salary payments and other benefits to their employees, to secure debtor in possession financing and other customary relief. On February 27, 2019, PG&E Corporation and the Utility received final approval of the first day motion to continue wage and salary payments and other benefits to their employees (with one limited objection with respect to a discrete matter having been preserved by the Bankruptcy Court) and certain other first day motions for customary relief. Hearings on certain other first day motions, including a hearing to consider final approval of PG&E Corporation’s and the Utility’s motions to continue their existing cash management system and to approve their debtor in possession financing, have not been held and no assurances can be given that the Bankruptcy Court will approve such motions on a final basis. PG&E Corporation and the Utility are unable to predict the date of the final hearing with respect to such motions, but there are hearings currently scheduled for March 12, March 13 and March 27, 2019.

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement. See Note 4 above for a description of the DIP Credit Agreement.

The commencement of the Chapter 11 Cases constituted an event of default or termination event, 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 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 4 above. The filing of the Chapter 11 Cases may also provide the counterparties under certain commodity and related agreements with the right to declare an event of default and to seek termination of such rights subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

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.

As of February 28, 2019, the Utility had outstanding borrowings of $350 million under the DIP Revolving Facility and $30 million in face amount of outstanding letters of credit, with remaining availability of $1.12 billion under the DIP Revolving Facility.

US 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 issued a judgment of conviction against the Utility. The court sentenced the Utility to a 5-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after 3 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 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.

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 third-party 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 third-party 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 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.

167

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. The court also invited parties to comment by February 20, 2019, on the 2019 Wildfire Safety Plan that the Utility submitted to the CPUC on February 6, 2019.

168

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

| | Quarter ended | | | |
|---|---|---|---|---|
| (in millions, except per share amounts) | December 31 | September 30 | June 30 | March 31 |
| 2018 | | | | |
| PG&E CORPORATION | | | | |
| Operating revenues [1] | $4,088 | $ 4,381 | $4,234 | $4,056 |
| Operating income (loss) | (9,530 ) | 696 | (1,465 ) | 599 |
| Income tax provision (benefit) [2] | (2,765 ) | 15 | (593 ) | 51 |
| Net income (loss) [3] | (6,869 ) | 567 | (980 ) | 445 |
| Income (loss) available for common shareholders | (6,873 ) | 564 | (984 ) | 442 |
| Comprehensive income (loss) | (6,866 ) | 568 | (980 ) | 445 |
| Net earnings (loss) per common share, basic | (13.24 ) | 1.09 | (1.91 ) | 0.86 |
| Net earnings (loss) per common share, diluted | (13.24 ) | 1.09 | (1.91 ) | 0.86 |
| UTILITY | | | | |
| Operating revenues [1] | $4,088 | $ 4,382 | $4,234 | $4,056 |
| Operating income (loss) | (9,530 ) | 697 | (1,465 ) | 599 |
| Income tax provision (benefit) [2] | (2,765 ) | 14 | (592 ) | 48 |
| Net income (loss) [3] | (6,865 ) | 571 | (976 ) | 452 |
| Income (loss) available for common stock | (6,869 ) | 568 | (980 ) | 449 |
| Comprehensive income (loss) | (6,871 ) | 571 | (975 ) | 452 |
| | | | | |
| 2017 | | | | |
| PG&E CORPORATION | | | | |
| Operating revenues [4] | $4,100 | $ 4,517 | $4,250 | $4,268 |
| Operating income | 429 | 899 | 748 | 880 |
| Income tax provision [5] | 108 | 160 | 134 | 109 |
| Net income [6] | 118 | 553 | 410 | 579 |
| Income available for common shareholders | 114 | 550 | 406 | 576 |
| Comprehensive income | 118 | 553 | 411 | 579 |
| Net earnings per common share, basic | 0.22 | 1.07 | 0.79 | 1.13 |
| Net earnings per common share, diluted | 0.22 | 1.07 | 0.79 | 1.13 |
| UTILITY | | | | |
| Operating revenues [4] | $4,101 | $ 4,516 | $4,250 | $4,271 |
| Operating income | 434 | 834 | 749 | 883 |
| Income tax provision [5] | 33 | 138 | 136 | 120 |
| Net income [6] | 200 | 513 | 409 | 569 |
| Income available for common stock | 196 | 510 | 405 | 566 |
| Comprehensive income | 203 | 513 | 409 | 570 |

[1] 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.
[2] In the second and fourth quarters of 2018, the Utility had an income tax benefit as a result of pre-tax losses.
[3] 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.
[4] In the first quarter of 2017, the Utility recorded the remaining retroactive revenues related to the 2015 GT&S rate case decision authorized by the CPUC.

(5) In the fourth quarter of 2017, the Utility had lower income tax expense primarily due to lower operating income, which was partially offset by the impact of the Tax Act.
(6) In the second quarter of 2017, the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement. Also, in the third quarter of 2017, the Utility recorded a $350 million charge related to 2015 Butte fire third-party claims. In the first, second, and third quarters of 2017, the Utility recorded $7 million, $14 million, and $276 million, respectively, for probable insurance recoveries in connection with recovery of losses related to the 2015 Butte fire. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

169

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, 2018, 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, 2018.

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, 2018, 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 and subsidiaries (the "Company") as of December 31, 2018 and 2017, the Company's related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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 Company's internal control over financial reporting as of December 31, 2018, 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 28, 2019 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 13 to the financial statements, the 2017 Northern California wildfires and the 2018 Camp wildfire may result in material losses to the Company, which contributed to the Company's decision to voluntarily file for bankruptcy as discussed below.  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 Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Bankruptcy Proceedings

As discussed in Note 1 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.

/s/ DELOITTE & TOUCHE LLP
February 28, 2019
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 and subsidiaries (the "Utility") as of December 31, 2018 and 2017, and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the schedule 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 28, 2019 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 13 to the financial statements, the 2017 Northern California wildfires and the 2018 Camp wildfire may result in material losses to the Utility, which contributed to the Utility's decision to voluntarily file for bankruptcy as discussed below. These circumstances and uncertainties inherent in the bankruptcy proceedings raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Bankruptcy Proceedings

As discussed in Note 1 to the financial statements, on January 29, 2019, the Utility 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
February 28, 2019
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, 2018, 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, 2018, 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, 2018, of the Company and our report dated February 28, 2019, 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
February 28, 2019

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, 2018, 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, 2018, 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, 2018, of the Utility and our report dated February 28, 2019, 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 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
February 28, 2019

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, 2018, 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 2018 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, 2018, 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, 2018 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

Not applicable.

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 2018 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 2019 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 2019 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 2018 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 2019 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 - 2018," "Grants of Plan-Based Awards in 2018," "Outstanding Equity Awards at Fiscal Year End - 2018," "Option Exercises and Stock Vested During 2018," "Pension Benefits – 2018," "Non-Qualified Deferred Compensation – 2018," "Potential Payment Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2018 Director Compensation" in the Joint Proxy Statement relating to the 2019 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 2019 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2018 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 | 6,607,418 (1) | $ 41.25 (2) | 15,150,532 (3) |
| Equity compensation plans not approved by shareholders | — | — | — |
| Total equity compensation plans | 6,607,418 (1) | $ 41.25 (2) | 15,150,532 (3) |

(1) Includes 9,699 phantom stock units, 2,041,071 restricted stock units and 3,030,422 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 2016, reflects the actual payout percentage of 0% for performance shares using a total shareholder return metric and 100% for performance shares using safety and affordability metrics. The actual number of shares issued can range from 0% to 200% 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.
(2) This is the weighted average exercise price for the 1,526,227 options outstanding as of December 31, 2018.
(3) Represents the total number of shares available for issuance under all PG&E Corporation's equity compensation plans as of December 31, 2018. Stock-based awards granted under these plans include restricted stock units, performance shares 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 5 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 2019 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 2019 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, 2018, 2017, and 2016 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2018 and 2017 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2018, 2017, and 2016 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2018, 2017, and 2016 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, 2018 and 2017 and for the Years Ended December 31, 2018, 2017, and 2016.

Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2018, 2017, and 2016.

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
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| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | |

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| | 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 December 16, 2016 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 3.3) |
| 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) |

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| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of August 21, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2018 (File No. 1-2348), Exhibit 3.01) |
| 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 | Fourth Supplemental Indenture, dated as of October 21, 2008, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Fifth Supplemental Indenture, dated as of November 18, 2008, relating to the issuance of $200,000,000 principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | 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) |
| 4.9 | Seventh Supplemental Indenture, dated as of June 11, 2009, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due June 10, 2010 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | 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) |
| 4.11 | 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) |
| 4.12 | 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) |
| 4.13 | 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 |

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| | $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) |
| 4.14 | 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) |

178

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| 4.15 | 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) |
| 4.16 | 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) |
| 4.17 | 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) |
| 4.18 | 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) |
| 4.19 | 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) |
| 4.20 | 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) |
| 4.21 | 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) |
| 4.22 | 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) |
| 4.23 | 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) |
| 4.24 | 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) |
| 4.25 | 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) |
| 4.26 | 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 |

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| | (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.27 | 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) |

179

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| 4.28 | 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) |
| 4.29 | 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) |
| 4.30 | 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) |
| 4.31 | 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) |
| 4.32 | 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) |
| 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 |

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| | 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 | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 2, 2016 (File No. 1-2348), Exhibit 10.1) |

180

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| 10.7 | Term Loan Agreement, dated as of February 23, 2017, 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, 2017 (File No. 1-2348), Exhibit 10.1) |
| 10.8 | 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) |
| 10.9 | 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) |
| 10.10 | 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) |
| 10.11 | 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) |
| 10.12* | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant 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, 2015 (File No. 1-12609), Exhibit 10.16) |
| 10.13* | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for non-annual award 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 10.08) |
| 10.14* | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant 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, 2015 (File No. 1-12609), Exhibit 10.17) |
| 10.15* | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant 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, 2015 (File No. 1-12609), Exhibit 10.18) |
| 10.16* | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-12609), Exhibit 10.4) |
| 10.17* | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant 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, 2015 (File No. 1-12609), Exhibit 10.5) |
| 10.18* | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant 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, 2015 (File No. 1-12609), Exhibit 10.7) |
| 10.19* | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant 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, |

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| | 2015 (File No. 1-12609), Exhibit 10.8) |
| 10.20* | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609), Exhibit 10.2) |
| 10.21* | Separation Agreement between PG&E Corporation and Geisha J. Williams dated January 12, 2019 |
| 10.22* | Separation Agreement between Pacific Gas and Electric Company and Pat Hogan dated January 7, 2019 |
| 10.23* | 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) |
| 10.24* | 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) |

181

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| 10.25* | 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) |
| 10.26* | 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) |
| 10.27* | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Janet Loduca dated December 3, 2018 |
| 10.28* | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Steven E. Malnight dated September 4, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2018 (File No. 1-12609), Exhibit 10.02) |
| 10.29* | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Kathleen B. Kay dated September 4, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2018 (File No. 1-12609), Exhibit 10.03) |
| 10.30* | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Laurie M. Giammona dated June 27, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2018 (File No. 1-12609), Exhibit 10.02) |
| 10.31* | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Jesus Soto dated June 27, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2018 (File No. 1-12609), Exhibit 10.03) |
| 10.32* | 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) |
| 10.33* | 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) |
| 10.34* | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.35* | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.36* | 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) |
| 10.37* | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2017 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2017 (File No. 1-12609), Exhibit 10.2) |
| 10.38* | 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) |
| 10.39* | 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) |
| 10.40* | 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. |

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| | | 1-12609, Exhibit 10.31) |
| 10.41 | * | 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) |
| 10.42 | * | 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) |
| 10.43 | * | Amendment to the Postretirement Life Insurance Plan of the 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) |

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| 10.44* | Amendment to the Postretirement Life Insurance Plan of the 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) |
| 10.45* | Postretirement Life Insurance Plan of the 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) |
| 10.46* | 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) |
| 10.47* | 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) |
| 10.48* | 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) |
| 10.49* | 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) |
| 10.50* | Form of Restricted Stock Unit Agreement for 2018 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Inventive 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) |
| 10.51* | 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) |
| 10.52* | 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) |
| 10.53* | 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) |
| 10.54* | 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) |
| 10.55* | 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) |
| 10.56* | Form of Restricted Stock Unit Agreement for 2015 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, 2015 (File No. 1-12609), Exhibit 10.4) |
| 10.57* | 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) |
| 10.58* | 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) |
| 10.59* | 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) |
| 10.60* | |

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| | | 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) |
| 10.61 | * | 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) |
| 10.62 | * | 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) |
| 10.63 | * | 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) |

183

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| 10.64 | * | Form of Performance Share Agreement subject to financial goals for 2015 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, 2015 (File No. 1-12609), Exhibit 10.5) |
| 10.65 | * | 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) |
| 10.66 | * | 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) |
| 10.67 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 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, 2015 (File No. 1-12609), Exhibit 10.6) |
| 10.68 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, 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) |
| 10.69 | * | 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) |
| 10.70 | * | 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) |
| 10.71 | * | 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) |
| 10.72 | * | 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) |
| 10.73 | * | 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) |
| 10.74 | * | 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) |
| 10.75 | * | 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) |
| 10.76 | * | 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) |
| 10.77 | * | 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) |
| 21 | | Subsidiaries of the Registrant |
| 23.1 | | PG&E Corporation Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 23.2 | | Pacific Gas and Electric Company Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | |

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|---|---|---|
| | | 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 |
| 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 |

* 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.

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, 2018 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<br>(Registrant) | | PACIFIC GAS AND ELECTRIC COMPANY<br>(Registrant) |
| | JOHN R. SIMON<br>John R. Simon | | MICHAEL A. LEWIS<br>Michael A. Lewis |
| By: | Interim Chief Executive Officer | By: | Senior Vice President, Electric Operations |
| Date: | February 28, 2019 | Date: | February 28, 2019 |
| | | | STEVEN E. MALNIGHT<br>Steven E. Malnight |
| | | By: | Senior Vice President, Energy Supply and Policy |
| | | Date: | February 28, 2019 |
| | | | JESUS SOTO, Jr.<br>Jesus Soto, Jr. |
| | | By: | Senior Vice President, Gas Operations |
| | | Date: | February 28, 2019 |

| Signature | Title | Date |
|---|---|---|
| A. Principal Executive Officers | | |
| John R. Simon | Interim Chief Executive Officer (PG&E Corporation) | February 28, 2019 |

| | | |
|---|---|---|
| Michael A. Lewis | Senior Vice President, Electric Operations (Pacific Gas and Electric Company) | February 28, 2019 |

186

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|---|---|---|
| Steven E. Malnight | Senior Vice President, Energy Supply and Policy (Pacific Gas and Electric Company) | February 28, 2019 |
| Jesus Soto, Jr. | Senior Vice President, Gas Operations (Pacific Gas and Electric Company) | February 28, 2019 |
| Jason P. Wells | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 28, 2019 |
| David S. Thomason | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 28, 2019 |

C. Principal Accounting Officer

| | | |
|---|---|---|
| David S. Thomason | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 28, 2019 |

D. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)

| | | |
|---|---|---|
| *LEWIS CHEW<br>Lewis Chew | Director | February 28, 2019 |
| *FRED J. FOWLER<br>Fred J. Fowler | Director | February 28, 2019 |
| *RICHARD C. KELLY<br>Richard C. Kelly | Director<br>Chair of the Board (PG&E Corporation) | February 28, 2019 |
| *ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 28, 2019 |
| *RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 28, 2019 |
| *FORREST E. MILLER<br>Forrest E. Miller | Director<br>Chair of the Board (Pacific Gas and Electric Company) | February 28, 2019 |
| *BENITO MINICUCCI<br>Benito Minicucci | Director | February 28, 2019 |

187

| | | |
|---|---|---|
| *ERIC D. MULLINS<br>Eric D. Mullins | Director | February 28, 2019 |
| *ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 28, 2019 |
| *BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 28, 2019 |
| *ANNE SHEN SMITH<br>Anne Shen Smith | Director | February 28, 2019 |
| *By:<br>Janet C. Loduca, Attorney-in-Fact | | February 28, 2019 |

PG&E CORPORATION

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

| | Years Ended December 31, | | |
|---|---|---|---|
| (in millions, except per share amounts) | 2018 | 2017 | 2016 |
| Administrative service revenue | $90 | $63 | $70 |
| Operating expenses | (91) | (5) | (73) |
| Interest income | 2 | 1 | 1 |
| Interest expense | (15) | (11) | (10) |
| Other income (expense) | (2) | 4 | 2 |
| Equity in earnings of subsidiaries | (6,832) | 1,667 | 1,388 |
| Income before income taxes | (6,848) | 1,719 | 1,378 |
| Income tax provision (benefit) | 3 | 73 | (15) |
| Net income | $(6,851) | $1,646 | $1,393 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $0, and $1, at respective dates) | $4 | $1 | $(2) |
| Total other comprehensive income (loss) | 4 | 1 | (2) |
| Comprehensive Income | $(6,847) | $1,647 | $1,391 |
| Weighted Average Common Shares Outstanding, Basic | 517 | 512 | 499 |
| Weighted Average Common Shares Outstanding, Diluted | 517 | 513 | 501 |
| Net earnings per common share, basic | $(13.25) | $3.21 | $2.79 |
| Net earnings per common share, diluted | $(13.25) | $3.21 | $2.78 |

PG&E CORPORATION

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED BALANCE SHEETS

| | Balance at December 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | $373 | $2 |
| Advances to affiliates | 44 | 24 |
| Income taxes receivable | 18 | 27 |
| Total current assets | 435 | 53 |
| Noncurrent Assets | | |
| Equipment | 2 | 3 |
| Accumulated depreciation | (2) | (3) |
| Net equipment | — | — |
| Investments in subsidiaries | 12,722 | 19,514 |
| Other investments | 162 | 144 |
| Intercompany receivable | — | 72 |
| Deferred income taxes | 187 | 123 |
| Total noncurrent assets | 13,071 | 19,853 |
| Total Assets | $13,506 | $19,906 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | 300 | 132 |
| Long-term debt, classified as current | 350 | — |
| Accounts payable – other | 16 | 6 |
| Other | 17 | 23 |
| Total current liabilities | 683 | 161 |
| Noncurrent Liabilities | | |
| Long-term debt | — | 350 |
| Other | 172 | 175 |
| Total noncurrent liabilities | 172 | 525 |
| Common Shareholders' Equity | | |
| Common stock | 12,910 | 12,632 |
| Reinvested earnings | (250) | 6,596 |
| Accumulated other comprehensive income (loss) | (9) | (8) |
| Total common shareholders' equity | 12,651 | 19,220 |
| Total Liabilities and Shareholders' Equity | $13,506 | $19,906 |

PG&E CORPORATION

SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Cash Flows from Operating Activities: | | | |
| Net income | $(6,851) | $1,646 | $1,393 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 78 | 20 | 74 |
| Equity in earnings of subsidiaries | 6,833 | (1,667) | (1,388) |
| Deferred income taxes and tax credits-net | (62) | 139 | 11 |
| Current income taxes receivable/payable | 9 | (2) | (1) |
| Other | 41 | (75) | (24) |
| Net cash provided by operating activities | 48 | 61 | 65 |
| Cash Flows From Investing Activities: | | | |
| Investment in subsidiaries | (45) | (455) | (835) |
| Dividends received from subsidiaries [1] | — | 784 | 911 |
| Net cash provided by (used in) investing activities | (45) | 329 | 76 |
| Cash Flows From Financing Activities: | | | |
| 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 | 200 | 395 | 822 |
| Common stock dividends paid [2] | — | (1,021) | (921) |
| Net cash provided by (used in) financing activities | 368 | (494) | (99) |
| Net change in cash and cash equivalents | 371 | (104) | 42 |
| Cash and cash equivalents at January 1 | 2 | 106 | 64 |
| Cash and cash equivalents at December 31 | $373 | $2 | $106 |
| Supplemental disclosure of cash flow information | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $(13) | $(9) | $(9) |
| Income taxes, net | 10 | — | (13) |
| Supplemental disclosure of noncash investing and financing activities | | | |
| Common stock dividends declared but not yet paid | $— | $— | $248 |
| Noncash common stock issuances | — | 21 | 20 |

[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 July and October of 2016 and January and April of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of $0.49 per share. In January and April of 2016, respectively, PG&E Corporation paid quarterly common stock dividends of

$0.455 per share.

191

PG&E Corporation

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2018, 2017, and 2016
(in millions)

| Description | Balance at Beginning of Period | Additions Charged to Costs and Expenses | Additions Charged to Other Accounts | Deductions [2] | Balance at End of Period |
|---|---|---|---|---|---|
| Valuation and qualifying accounts deducted from assets: | | | | | |
| 2018: | | | | | |
| Allowance for uncollectible accounts [1] | $ 64 | $ 34 | $ — | $ 42 | $ 56 |
| 2017: | | | | | |
| Allowance for uncollectible accounts [1] | $ 58 | $ 55 | $ — | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ — | $ 46 | $ 58 |

[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

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2018, 2017, and 2016
(in millions)

| Description | Balance at Beginning of Period | Additions Charged to Costs and Expenses | Charged to Other Accounts | Deductions [2] | Balance at End of Period |
|---|---|---|---|---|---|
| Valuation and qualifying accounts deducted from assets: | | | | | |
| 2018: | | | | | |
| Allowance for uncollectible accounts [1] | $ 64 | $ 34 | $ — | $ 42 | $ 56 |
| 2017: | | | | | |
| Allowance for uncollectible accounts [1] | $ 58 | $ 55 | $ — | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ — | $ 46 | $ 58 |

(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.

193