PG&E Corp
Form 10-K
February 16, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2016

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to ___________

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

77 Beale Street, P.O. Box 770000	77 Beale Street, P.O. Box 770000
San Francisco, California 94177	San Francisco, California 94177
(Address of principal executive offices) (Zip Code)	(Address of principal executive offices) (Zip Code)
(415) 973-1000	(415) 973-7000
(Registrant's telephone number, including area code)	(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock,	NYSE MKT LLC

cumulative, par value $25 per share:
Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36%
Nonredeemable: 6%, 5.50%, 5%

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

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

PG&E Corporation
Pacific Gas and Electric Company

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

PG&E Corporation	Pacific Gas and Electric Company
Large accelerated filer	Large accelerated filer
Accelerated filer	Accelerated filer
Non-accelerated filer	Non-accelerated filer
Smaller reporting company	Smaller reporting company

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2016, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$31,807 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 7, 2017:

PG&E Corporation:	507,782,249 shares
Pacific Gas and Electric Company:	264,374,809 shares (wholly owned by PG&E Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

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

Designated portions of the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

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

GLOSSARY

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

2016 Form 10-K	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2016
AB	Assembly Bill
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
ARO	asset retirement obligation
ASU	accounting standard update issued by the FASB (see below)
CAISO	California Independent System Operator
Cal Fire	California Department of Forestry and Fire Protection
CARB	California Air Resources Board
CCA	Community Choice Aggregator
Central Coast Board	Central Coast Regional Water Quality Control Board
CEC	California Energy Resources Conservation and Development Commission
CO2	carbon dioxide
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DER	distributed energy resources
Diablo Canyon	Diablo Canyon nuclear power plant
DOE	U.S. Department of Energy
DOGGR	Division of Oil, Gas and Geothermal Resources
DOI	U.S. Department of the Interior
DTSC	Department of Toxic Substances Control
EMANI	European Mutual Association for Nuclear Insurance
EPA	Environmental Protection Agency
EPS	earnings per common share
EV	electric vehicle
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. Generally Accepted Accounting Principles
GHG	greenhouse gas
GRC	general rate case
GT&S	gas transmission and storage
IOUs	investor-owned utility(ies)
IRS	Internal Revenue Service
LTIP	long-term incentive plan
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K

MOU	memorandum of understanding
NAV	net asset value
NDTCP	Nuclear Decommissioning Cost Triennial Proceedings
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
OII	order instituting investigation
ORA	Office of Ratepayer Advocates
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	pipeline safety enhancement plan
QF	qualifying facility
Regional Board	California Regional Water Quality Control Board, Lahontan Region

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REITS	real estate investment trust
RFO	requests for offers
ROE	return on equity
RPS	renewable portfolio standard
SB	Senate Bill
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
TE	transportation electrification
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)
Water Board	California State Water Resources Control Board

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PART I

ITEM 1. BUSINESS

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

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

At December 31, 2016, PG&E Corporation and the Utility had approximately 24,000 regular employees, approximately 30 of which were employees of PG&E Corporation. Of the Utility's regular employees, approximately 14,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW"); the Engineers and Scientists of California ("ESC"); and the Service Employees International Union ("SEIU"). A new SEIU collective bargaining agreement was ratified in December 2016 and is effective August 1, 2016 through December 31, 2019. Two new agreements (Physical and Clerical) with IBEW and an agreement with ESC were ratified in 2016 and were retroactive to January 1, 2016. They will expire on December 31, 2019.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com, as promptly as practicable after they are filed with, or furnished to, the SEC. Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's 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. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on these websites is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC.

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

Regulatory Environment

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

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

The California Public Utilities Commission

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

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. In September 2016, the CPUC adopted improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replaces the previous safety citation programs.

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

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

The Federal Energy Regulatory Commission and the California Independent System Operator

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility's transmission systems with other electric system and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electric transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impose fines of up to $1 million per day for violations of certain federal statutes and regulations.

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

The Nuclear Regulatory Commission

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electricity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. (For more information about Diablo Canyon, see "Regulatory Matters – Diablo Canyon Nuclear Power Plant" in MD&A and Item 1A. Risk Factors below.)

Other Regulators

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

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

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

Ratemaking Mechanisms

The Utility’s rates for electricity and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service including 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 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. 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, ensure that the Utility will fully collect its authorized base revenue requirements. 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 MD&A) within its authorized base revenue requirements.

Both electric and gas rates vary depending on seasons mostly due to the influence of weather. Electricity rates increase during the summer months (May – October) because of higher demand, driven by air conditioning loads, while gas service rates generally increase during the winter months (November – March) to account for the gas peak due to heating.

During 2016, the CPUC continued to implement state law requirements to reform residential electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. (See "Legislative and Regulatory Initiatives" in MD&A for more information on specific CPUC proceedings.)

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 – 2014 – 2015 Energy Efficiency Incentive Awards" in MD&A.)

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 electricity distribution, natural gas distribution, and Utility owned electricity 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 ORA 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 current GRC proceeding, see "Regulatory Matters –2017 General Rate Case" in 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 proceeding, the CPUC approves the annual revenue requirements for the first year (or "test year") of the GT&S period and typically determines annual increases in revenue requirements for attrition years of the GT&S period. Parties in the Utility's GT&S rate case include the ORA and TURN, who generally represent the overall interests of residential customers, as well as other intervenors who represent other business, community, customer, and union interests. (For more information, see "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" in MD&A.)

Cost of Capital Proceedings

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2017, 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%. The CPUC 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. On February 25, 2016, the CPUC issued a decision granting a petition for modification filed by the Utility and the other California IOUs to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered for 2017.

On February 6, 2017, the Utility and other California IOUs entered into a MOU with the CPUC, ORA, and TURN to extend the next cost of capital application filing deadline two years to April 22, 2019 for the year 2020. To implement the MOU, on February 7, 2016, the IOUs, ORA, and TURN filed with the CPUC a petition for modification of prior CPUC decisions addressing cost of capital. If the petition for modification is approved as submitted it would reduce the Utility's ROE from 10.40% to 10.25% and reset the Utility's authorized cost of long-term debt and preferred stock beginning January 1, 2018. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity would remain unchanged. The Utility's cost of capital adjustment mechanism would not operate in 2017 but could operate in 2018 to change the cost of capital for 2019. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the existing terms of the mechanism. Concurrently with the petition for modification, the Utility and other California IOUs also sent a letter to the executive director of the CPUC requesting that the existing April 2017 filing due date for the 2018 cost of capital be deferred while the CPUC is considering the petition for modification. On February 13, 2017, the executive director of the CPUC granted the request. As extended, the Utility and the other California IOUs would file their next cost of capital applications 60 days after the effective date of the CPUC decision on the petition for modification, or April 20, 2017, whichever is later, if the CPUC does not grant the petition for modification.

The Utility expects that the CPUC may issue a decision in the first half of 2017. (For more information, see "Regulatory Matters –CPUC Cost of Capital" in MD&A.)

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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 generally files 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. These FERC-approved rates are included: 1) by the CPUC in the Utility's retail electric rates and are collected from retail electric customers; and 2) by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see "Regulatory Matters – FERC Transmission Owner Rate Cases" in 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.

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 electricity 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 bundled customer procurement plans based on long-term demand forecasts. The Utility's most recent bundled customer procurement plan was approved in October 2015, and will remain in effect until the plan is superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved bundled customer procurement plans 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 cost of replacement power procured due to unplanned outages at Utility owned generation facilities may be disallowed.

The Utility recovers its electricity 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 electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electricity 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 13 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 electricity rates.

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

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

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

Costs Associated with Public Purpose and Customer Programs

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income customers, known as California Alternate Rates for Energy ("CARE"), which is subsidized 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 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 August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025. (For more information, see “Legislative and Regulatory Initiatives” in MD&A.)

Electric Utility Operations

The Utility generates electricity and provides electricity 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 most 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.

The Utility has continued to invest in its vision for a future electric grid which will allow customers to choose new, advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. In addition, in December 2016, the CPUC issued a final decision establishing a three-year EV program for the Utility to deploy up to 7,500 charging stations. (For more information, see “Legislative and Regulatory Initiatives” in MD&A.)

Electricity Resources

The Utility is required to maintain generating 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 electricity resources within its portfolio in the most cost-effective way.

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 2016 represented by each major electricity resource, and further discussed below.

Total 2016 Actual Electricity Generated and Procured – 68,441 GWh (1):

	Percent of Bundled Retail Sales	
Owned Generation Facilities		
Nuclear	24.2 %	
Small Hydroelectric	1.3 %	
Large Hydroelectric	9.8 %	
Fossil fuel-fired	7.3 %	
Solar	0.5 %	
Total		43.1 %
Qualifying Facilities		
Renewable	2.6 %	
Non-Renewable	5.1 %	
Total		7.7 %
Irrigation Districts and Water Agencies		
Large Hydroelectric	0.5 %	
Total		0.5 %
Other Third-Party Purchase Agreements		
Renewable	28.4 %	
Large Hydroelectric	2.1 %	
Non-Renewable	4.8 %	
Total		35.3 %
Others, Net (2)		13.4 %

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.

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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. The Utility will 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.

As indicated below, the Utility's application and joint proposal to retire Diablo Canyon include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

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 2016, 32.8% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 28.4% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (2.6%), the Utility's small hydroelectric facilities (1.3%), and the Utility's solar facilities (0.5%).

The total 2016 renewable deliveries shown above were comprised of the following:

Type	GWh	Percent of Bundled Retail Sales
Biopower	2,958	4.3%
Geothermal	3,705	5.4%
Small Hydroelectric	1,800	2.6%
Solar	8,598	12.6%
Wind	5,419	7.9%
Total	22,480	32.8%

Energy Storage. As required by California law, the CPUC has opened a proceeding to establish 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 2020, 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 conduct biennial competitive RFOs to help meet its interim storage targets.

The Utility conducted an RFO in 2014. The Utility's 2014 energy storage target was 90 MW, some of which the Utility met through already existing projects, or projects anticipated to result from other CPUC proceedings. As a result of the 2014 RFO, 70 MW of transmission and distribution contracts have been approved by the CPUC. Contracts for 6MW were rejected by the CPUC, including a behind-the-meter project. Additionally, contracts for 13 MW were withdrawn by the Utility.

The Utility's 2016 energy storage target is 120 MW. On November 30, 2016, the Utility issued its 2016 RFO. The Utility must submit all executed contracts from the 2016 RFO to the CPUC for approval by December 1, 2017. The Utility expects to increase the amount of storage it is attempting to procure in its 2016 RFO by the shortfall from the 2014 target.

Owned Generation Facilities. At December 31, 2016, 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	104	2,684
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		137	7,691

(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. (See "Diablo Canyon Nuclear Power Plant" in MD&A and Item 1A. Risk Factors.)

(2) The Utility's hydroelectric system consists of 107 generating units at 67 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 Five Points solar station (15 MW), Westside solar station (15 MW), Stroud solar station (20 MW), Huron solar station (20 MW), Cantua solar station (20 MW), Giffen solar station (10 MW), Gates solar station (20 MW), West Gates solar station (10 MW) and Guernsey solar station (20 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 13 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2016, the Utility owned approximately 18,400 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 92 electric transmission substations with a capacity of approximately 64,600 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.

In 2013, the Utility, MidAmerican Transmission, LLC, and Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in the Fresno, Madera and Kings counties area. The CAISO has stated that the 2022 in-service date for the 70-mile line has been postponed, and has placed the project on hold. The Utility has stopped all work on the project pending a decision from the CAISO that could defer or cancel the project. A decision by the CAISO is expected by March 2018. In addition, as a part of the CAISO's 2016-2017 planning efforts, the CAISO conducted a review of a number of local area low voltage transmission projects in the Utility’s service territory that were predominantly load forecast driven. As a result of the review, the CAISO found that a number of lower-voltage transmission projects were no longer required and recommended cancelling or requiring further review in the 2017-2018 planning cycle.

On March 29, 2026 the Utility entered into an agreement with TransCanyon, LLC, a joint venture between subsidiaries of Berkshire Hathaway Energy and Pinnacle West Capital Corporation, to jointly pursue competative transmission opportunities solicited by the CAISO. The Utility and TransCanyon intend to jointly engage in the development of future transmission infastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

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Throughout 2016, the Utility upgraded several critical substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety. The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to secure access to renewable generation resources and replace aging or obsolete equipment and improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment.

Electricity Distribution

The Utility's electricity distribution network consists of approximately 142,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 59 transmission switching substations, and 606 distribution substations, with a capacity of approximately 31,800 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. In 2016 the Utility commenced operations in a new electric distribution control center facility in Concord, California; along with the existing distribution control centers in Rocklin and Fresno, California, these control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2016, the Utility continued to deploy its Fault Location, Isolation, and Service Restoration circuit technology which involves the rapid operation of smart switches to reduce the duration of customer outages. Another 89 circuits were outfitted with this equipment, bringing the total deployment to 789 of the Utility’s 3,200 distribution circuits. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2017.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2014 to 2016 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 2016, 2015 and 2014.

	2016	2015	2014
Customers (average for the year)	5,349,691	5,311,178	5,276,025
Deliveries (in GWh) (1)	83,017	85,860	86,303
Revenues (in millions):			
Residential	$5,409	$5,032	$4,784
Commercial	5,396	5,278	5,141
Industrial	1,525	1,555	1,543
Agricultural	1,226	1,233	1,172
Public street and highway lighting	80	83	79
Other (2)	(68)	(84)	(172)
Subtotal	13,568	13,097	12,547
Regulatory balancing accounts (3)	297	560	1,109
Total operating revenues	$13,865	$13,657	$13,656
Selected Statistics:			
Average annual residential usage (kWh)	6,115	6,294	6,458
Average billed revenues per kWh:			
Residential	$0.1887	$0.1719	$0.1603
Commercial	0.1716	0.1640	0.1585
Industrial	0.0990	0.0973	0.0998
Agricultural	0.1814	0.1610	0.1516
Net plant investment per customer	$7,195	$6,660	$6,339

(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 a remittance of revenue to the Department of Water Resources ("DWR") (the Utility acts as a billing and collection agent on behalf of the DWR), 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 90% of core customers, representing nearly 78% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers. 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 fluctuated generally based on market conditions. During 2016, the Utility purchased approximately 307,100 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 14% of the total natural gas volume the Utility purchased during 2016.

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, 2016, the Utility's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,700 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. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect 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 13 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.

As of December 31, 2016 the Utility had installed 268 automatic and remote control shut-off valves on its gas transmission system, as specified in the eleventh of twelve safety recommendations made by the NTSB following its investigation of the San Bruno accident. The NTSB closed that recommendation in 2015. The final safety recommendation, considered open and acceptable by the NTSB, involves ensuring that all high consequence pipeline mileage in the Utility's gas transmission system has been hydrostatically tested. As of December 31, 2016, the Utility has hydrostatically tested about 840 miles and completed the majority of this safety recommendation. The Utility currently plans to complete the NTSB recommendation by 2022 for the remaining approximately 28 aggregate pipeline miles (involving hundreds of primarily short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines).

In addition, in 2016, the Utility inspected 260 miles of transmission pipeline using in-line inspection tools and upgraded an additional 107 miles of transmission pipeline to allow for the use in-line inspection tools, replaced 127 miles of distribution main, and completed the installation of over 25,000 line makers to more easily identify the locations of gas pipelines.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2014 through 2016 (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 2016, 2015 and 2014.

	2016	2015	2014
Customers (average for the year)	4,442,379	4,415,332	4,394,283
Gas purchased (MMcf)	208,260	209,194	202,215
Average price of natural gas purchased	$1.83	$2.11	$4.09
Bundled gas sales (MMcf):			
Residential	149,483	144,885	143,514
Commercial	46,507	43,888	42,080
Total Bundled Gas Sales	195,990	188,773	185,594
Revenues (in millions):			
Bundled gas sales:			
Residential	$1,968	$1,816	$1,683
Commercial	439	403	419
Other	149	125	51
Bundled gas revenues	2,556	2,344	2,153
Transportation service only revenue	800	649	662
Subtotal	3,356	2,993	2,815
Regulatory balancing accounts	446	183	617
Total operating revenues	$3,802	$3,176	$3,432
Selected Statistics:			
Average annual residential usage (Mcf)	36	35	34
Average billed bundled gas sales revenues per Mcf:			
Residential	$13.10	$12.53	$11.72
Commercial	9.45	9.18	9.96
Net plant investment per customer	$2,808	$2,573	$2,468

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 which do not affirmatively elect to continue to receive electricity from a utility.

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.

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 Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing. These factors result in a shift of cost responsibility for grid and related services to other customers of 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.

Competition in the Natural Gas Industry

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

Environmental Regulation

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of 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 13 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 Department of Toxic Substances Control, 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 13 of the Notes to the Consolidated Financial Statements in Item 8.

Air Quality and Climate Change

The Utility's electricity generation plants, natural gas pipeline operations, 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.

In December 2009, the EPA concluded that GHG emissions contribute to climate change and issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. In May 2014, the U.S. Global Change Research Program (a confederation of the research arms of thirteen federal departments and agencies) released its third National Climate Assessment, which stated that the global climate is changing and that impacts related to climate change are already evident in many sectors and are expected to become increasingly disruptive across the nation throughout this century and beyond.

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.

In August 2015, the EPA published final regulations under section 111(b) of the Clean Air Act to control CO_2 emissions from new fossil fuel-fired power plants. While these regulations do not affect the Utility’s existing power plants, the regulations impose emission limitations on fossil fuel-fired power plants constructed after January 8, 2014 and will affect the design, construction, operation and cost of such power plants.

In August 2015, the EPA also published final regulations under section 111(d) of the Clean Air Act to control CO_2 emissions from existing fossil fuel-fired power plants. These regulations are designed to reduce power plant CO_2 emissions on a national basis by as much as 32% by 2030, compared with 2005 levels. States were required to submit final plans to comply with these regulations by September 2016, but were permitted to request an extension to file such plans until September 2018. It is uncertain whether and how these federal regulations will ultimately impact California, since existing state regulation currently requires, among other things, the gradual reduction of state-wide GHG emissions to 40% below 1990 levels by 2030. Following publication of the EPA’s regulations, in October 2015 West Virginia and several other states and parties challenged the EPA’s section 111(d) regulations in the United States Court of Appeals for the District of Columbia Circuit and petitioned the Court to stay the regulations pending review of the appeal on the merits. The D.C. Circuit denied the request for stay but in February 2016, the United States Supreme Court granted a stay of the section 111(d) regulations pending review of the appeal by the D.C. Circuit. The Supreme Court’s decision may affect the nature, extent and timing of implementation of these regulations. As described below, the Utility expects all costs and revenues associated with the state-wide, comprehensive cap-and-trade program to be passed through to customers.

With the change in federal administration from President Barack Obama to President Donald Trump, there is significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. The new administration has indicated that it intends to revoke the Clean Power Plan regulations and possibly withdraw from international efforts to combat climate change. Upon taking office, President Trump issued an executive order to freeze all regulations issued in the 60 days preceding his inauguration and directed the EPA and the White House to remove climate change-related materials and web pages, pending further review. It is assumed that the new administration also will take action to suspend all climate related regulatory and funding activities. In light of the potential 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 electricity 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. Additionally, Senate Bill 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. CARB is currently considering regulatory amendments to the cap-and-trade program to extend the program's authority 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.

Climate Change Mitigation and Adaptation Strategies. During 2016, the Utility continued its programs to develop strategies 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 adapt to the likely impacts of climate change on the Utility's future operations, including forming an officer-level coordinating committee to govern and oversee the Utility's activities. The Utility regularly reviews the most relevant scientific literature on climate change such as sea level rise, temperature changes, rainfall and runoff patterns, and wildfire risk, to help the Utility identify and evaluate climate change-related risks and develop the necessary adaptation strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including extreme storms, heat waves and wildfires 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.

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. The Utility's vegetation management activities also reduce the risk of wildfire impacts on electric and gas facilities. 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.

Notwithstanding the current high snowpack, 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 2015 totaled more than 54 million metric tonnes of CO−2 equivalent, two-thirds of which came from customer natural gas use. The following table shows the 2015 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 CO2 equivalent)
Fossil Fuel-Fired Plants (1)	2,875,176
Natural Gas Compressor Stations and Storage Facilities (2)	362,472
Distribution Fugitive Natural Gas Emissions	676,458
Customer Natural Gas Use (3)	43,022,557

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

(2) Including, but not limited to, compressor stations and storage facilities emitting more than 25,000 metric tonnes of CO2 equivalent annually.

(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. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities, as calculated by the CARB.

The following table shows the Utility's third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2015 as compared to the national average for electric utilities:

	Amount (pounds of CO2 per MWh)
U.S. Average (1)	1,143
Pacific Gas and Electric Company (2)	405

(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 approximately 40% of the Utility’s delivered electricity in 2015. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

	2015	2014
Total NOx Emissions (tons)	160	141
NOx Emissions Rate (pounds/MWh)	0.01	0.01
Total SO2 Emissions (tons)	17	14
SO2 Emissions Rate (pounds/MWh)	0.0011	0.0010

Water Quality

On May 19, 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 Fourth 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. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025, and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. Beginning in 2017, as required under the policy, the Utility will pay an annual interim mitigation fee until operations cease in 2024 and 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 Water 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 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 ("DOJ") and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. Through 2016, the Utility has been awarded an additional $99 million through these annual submissions, including $28 million for costs incurred between June 1, 2014 and May 31, 2015. The claim for the period June 1, 2015 through May 31, 2016 is currently under review by the DOE. These proceeds are being refunded to customers through rates. The settlement agreement, as amended, does not address costs incurred for spent fuel storage beyond 2016; an extension of the agreement for costs through 2019 is pending DOJ approval. Costs beyond 2016 could be subject to future litigation. 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.

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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 business, results of operations, financial condition, and stock price.

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

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

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. Such insurance coverage is subject to the terms and limitations of the available policies and may not be sufficient to cover the Utility's ultimate liability.

The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may change. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and the results of operations during the period such change occurred.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals. (For more information, see "Enforcement and Litigation Matters" in Item 7. MD&A and in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation’s and the Utility’s future financial results may 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 also could incur material costs and fines in connection with future investigations, citations, audits, or enforcement actions.

The Utility could incur material charges, including fines and other penalties, in connection with a potential settlement or litigated outcome of the CPUC’s investigation of the Utility’s compliance with the CPUC’s rules regarding ex parte communications. While on October 14, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility submitted a status report to the CPUC which proposed an update to the framework for resolving the proceeding and included a total of 164 communications in the scope of the proceeding, the Utility expects that the other parties may argue that the number of violations exceeds the 164 communications referenced in the status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. 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 the discussion under the heading “Regulatory Matters” in MD&A.)

The Utility also is a target of a number of investigations and government requests for information. 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. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The Utility was also contacted by certain other federal agencies with requests for information. While the Utility believes that these requests for information are routine, their outcome is uncertain. The Utility also is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility.

If these investigations or requests for information result in enforcement action against the Utility, the Utility could incur additional fines or penalties or suffer negative consequences described above in the immediately preceding risk factor. In addition, a negative outcome in any of these investigations or future enforcement actions may negatively affect the outcome of future ratemaking and regulatory proceedings; 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.

The Utility may incur fines and penalties in connection with the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way and the Penalty Decision. The Penalty Decision requires the SED to review the Utility's gas transmission operations (including the Utility's compliance with the remedies ordered by the Penalty Decision) and to perform annual audits of the Utility's record-keeping practices for a minimum of ten years. The SED could impose fines on the Utility or require the Utility to incur unrecoverable costs, or both, based on the outcome of these future audits. In addition, although PG&E Corporation and the Utility do not currently face the possibility of fines or penalties in the first phase of the CPUC's pending investigation into the Utility's safety culture since it has been categorized as rate setting, it is uncertain how a next phase, if any, would be categorized. (See the discussion under the heading "Regulatory Matters" in MD&A.)

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 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 results.

PG&E Corporation's and the Utility's future financial results could be materially affected by the conviction of the Utility in the federal criminal proceeding and by the debarment proceeding.

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 Utility has decided not to appeal the convictions.

The probation includes a requirement that the Utility not commit any local, state or federal crimes during the probation period. As part of the probation, the Utility is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

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

At December 31, 2016, PG&E Corporation and the Utility's Consolidated Balance Sheets included a $3 million accrual in connection with this matter. The Utility could incur material costs and additional penalties, 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 the monitor's compensation or costs resulting from recommendations of the monitor).

Also, in September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the San Bruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. On December 21, 2016, the Utility and the DOI entered into an interim administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect the federal government's business interests. The agreement will be effective until superseded by an amended agreement or determination. The agreement also provides that the DOI is still conducting a review to determine whether the Utility has an effective compliance and ethics program and that the DOI is required to use its best efforts to complete its review before the end of 2017. If the DOI determines that the Utility's program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s).

The Utility's conviction and the outcome of the debarment proceeding could harm the Utility's relationships with 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. As discussed under the heading "Regulatory Matters" in Item 7. MD&A, the SED continues evaluating PG&E Corporation's and the Utility's organizational culture and governance in the CPUC's pending investigation to examine the Utility's safety culture.

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 Utility's reputation (especially as a result of the Utility's conviction in the federal criminal trial), 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.

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, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas services.

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 storms, fires, accidents, 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's ability to recover its costs also may be affected by the economy and its impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers or the level of uncollectible bills could increase. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

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.

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. In particular, the Utility will incur additional costs to procure renewable energy to meet the higher targets established by California SB 350 that became effective on January 1, 2016. Despite the CPUC's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the costs are unreasonably above market.

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. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

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 net energy metering ("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. In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers will be required to pay an interconnection fee, will go on time of use rates, and will be required to pay some non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. However, the resulting rules will still put upward rate pressure on remaining customers, and remove the cap on the number of NEM customers. 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 states that it intends to revisit these rules in 2019.

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 capital investment would likely decline as well, in turn 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 adversely impact PG&E Corporation's and the Utility's financial results.

The CPUC has begun to implement rate reform to allow residential electric rates to more closely reflect the utilities' actual costs of providing service and decrease cost-subsidization among customer classes. Many aspects of rate reform are not yet finalized, including time-of-use rates and whether the utilities can impose a fixed charge on certain customers. 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 results could be materially affected.

Risks Related to Liquidity and Capital Requirements

PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, pay fines that may be imposed in the future, as well as costs related to rights-of-way and legal and regulatory costs. PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including the pending CPUC investigations and ratemaking proceedings. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, volatility in electricity or natural gas prices, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in Item 7. MD&A. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management's ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation's stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation and PG&E Corporation could be required to contribute capital to the Utility to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

PG&E Corporation's ability to meet its debt service and other financial obligations and to pay dividends on its common stock depends on the Utility's earnings and cash flows.

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. Under the CPUC’s rules applicable to utility holding companies, the Utility’s dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation’s Board of Directors give “first priority” to the Utility’s capital requirements, as determined to be necessary and prudent to meet the Utility’s obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this “first priority” obligation to include the requirement that PG&E Corporation “infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve.” In addition, before the Utility can pay common stock dividends to PG&E Corporation, the Utility must maintain its authorized capital structure with an average 52% equity component.

If the Utility were required to pay a material amount of fines or incur material unrecoverable costs in connection with the terms of the probation or monitorship, the pending CPUC investigations, or other enforcement matters, it would require incremental equity contributions from PG&E Corporation to restore its capital structure. PG&E Corporation common stock issuances used to fund such equity contributions could materially dilute EPS. (See “Liquidity and Financial Resources” in Item 7. MD&A.) Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility was unable to distribute cash to PG&E Corporation, or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend, or meet other obligations.

PG&E Corporation’s and the Utility’s ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%.

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 adversely affect PG&E Corporation's and the Utility's financial results. The Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event, or may not become available at a reasonable cost, or available at all.

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.) 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. 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;

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), and the failure to respond effectively to a catastrophic event;

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;

severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wild land and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;

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 damage 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

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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.

In particular, the Utility may incur material liability in connection with the Butte fire. (See "PG&E Corporation and the Utility may incur material liability in connection with Butte Fire" above.) Additionally, on January 12, 2017, a residential structure fire occurred in Yuba City, California resulting in the collapse of the house and injuries to two persons inside the house. The CPUC, a third-party engineering firm, and local fire and police officials are investigating the origin and cause of the incident. The Utility may incur material costs, including as a result of these investigations or any proceedings that could be commenced in connection with this incident.

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 results. Future insurance coverage may not be available at rates and on terms as favorable as the Utility's current insurance coverage or may not be available at all.

Further, California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages and takings as a result of the design, construction and maintenance of utility facilities, including its electric transmission lines. As a result of the strict liability standard applied to wildfires, recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of the ongoing drought, and the Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at comparable cost and terms as the Utility's current insurance coverage, 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 recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected.

The Utility's operational and information technology systems could fail to function properly or be improperly accessed or damaged by third parties (including cyber-attacks and physical acts) or damaged by severe weather, natural disasters, or other events. Any of these events could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense or liability to third parties.

The operation of the Utility's extensive electricity and natural gas systems relies on evolving and increasingly complex operational and information technology systems and network infrastructures that are interconnected with the systems and network infrastructure owned by third parties. All of the Utility's operational and technology systems and network infrastructure are vulnerable to disability or failures in the event of cyber-attacks and physical acts. Cyber-attacks are increasingly sophisticated and may include computer hacking, viruses, malware, social engineering, denial of service attacks, ransomware, destructive malware, or other means of disruption, destruction, or unauthorized access, acquisition or control. In addition, hardware, software, or applications the Utility develops or procures from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information security. Physical attacks may include acts of sabotage, acts of war, acts of terrorism, or other physical acts. The Utility's operational and information technology systems and networks are deemed critical infrastructure, and any failure or decrease in their functionality could, among other things, cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to generate, transport, deliver and store energy and gas, or otherwise operate in the most efficient manner or at all, undermine the Utility's performance of critical business functions, damage the Utility's assets or operations or those of third parties, and lead to reputational harm. As a result, such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, investigations, and regulatory actions that could result in fines and penalties, and loss of customers, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to host, maintain, modify, and update its systems and these third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience internal or external security incidents. Any incidents, disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification of existing systems or implementation of new systems could result in increased costs, the inability to track or collect revenues, or diversion of management's and employees' attention and resources, or negatively affect the Utility's ability to maintain effective financial controls or timely file required regulatory reports. The Utility also could be subject to patent infringement claims arising from the use of third-party technology by the Utility or by a third-party vendor.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject the Utility to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm the Utility's reputation.

The Utility and its third party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to the Utility's information technology systems, or confidential data, or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. 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 systems, infrastructure, or data, or the disruption of its operations, either of which could materially affect PG&E Corporation's and the Utility's financial condition and results of operations.

While the Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents, 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 power plants 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 results. In addition, the

Utility may be required under federal law to pay up to $255 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. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application includes a joint proposal between the Utility and certain interested parties, entered into on June 20, 2016. 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 the 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 and the Utility's financial results.

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 company. The Utility currently estimates that the additional cost of the employee retention program and the employee retraining and development program will be approximately $350 million. The Joint Proposal seeks confirmation from the CPUC that these costs will be recovered through the Utility's nuclear decommissioning electric rates. The employee retention and retraining and development programs are subject to bargaining with the Utility's labor unions. The Utility will also incur costs in connection with an employee severance program. The severance program was previously approved by the CPUC in prior nuclear decommissioning ratemaking proceedings.

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.) 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 before the licenses expire in 2024 and 2025. At December 31, 2016, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

At the state level, the California Water Board has 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%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. If the Utility obtains contingent approvals referred to herein that will result in retiring Diablo Canyon at the end of the current NRC operating licenses, the Utility will not be required to install cooling towers or implement alternative measures in order to comply with the California State Water Board Once-Through Cooling Water Policy, thus eliminating the regulatory uncertainty regarding the measures that could have been imposed on the Utility or of incurring a material charge related thereto. Even if the Utility is ultimately not required to install cooling towers, under the State Water Board's interim mitigation measures applicable to Diablo Canyon's operations prior to 2025, starting in 2016, it will be required to make payments to the California Coastal Conservancy to fund various environmental mitigation projects, that the Utility does not expect to exceed $5 million per year.

On June 28, 2016 the California State Lands Commission approved an extension of the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

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 results could be materially affected.

Risks Related to Environmental Factors

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, 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 13 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.) 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.

The Utility’s future operations may be affected by climate change that may have a material impact on PG&E Corporation’s and the Utility’s financial condition, results of operations, and cash flows.

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. While snowpack in the Sierra Nevada Mountains has been at higher than normal levels this winter, California has experienced ongoing drought in the past. If temperatures and the levels of precipitation in the Utility’s service territory continue to change, that could impact the levels of snowpack in the Sierra Nevada Mountains. 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, increasing temperatures and lower levels of precipitation could increase the occurrence of wildfires in the Utility’s service territory causing damage to the Utility’s facilities or the facilities of third parties on which the Utility relies to provide service, damage to third parties for loss of property, personal injury, or loss of life. In addition, flooding caused by rising sea levels could damage the Utility’s facilities, including hydroelectric assets such as dams and canals, and the electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, 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, and cash flows could be materially affected.

Other Risk Factors

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

The Utility’s financial results could be materially affected as a result of the recent change in federal administration from President Barack Obama to President Donald Trump. For example, the new administration has indicated tax reform as a priority. Tax reform outlines produced by both President Trump and the Tax Reform Task Force include proposals related to federal tax rates, deductions for state income taxes (and potentially property tax), interest expense deduction, capital expenditure deduction, and expensing plant. It is unclear what tax reform may be ultimately adopted. It is generally expected that a tax reform bill will be introduced in early 2017.

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

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility. If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility's compliance costs. In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility. In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, 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 results 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 results 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. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

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

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

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. In 2002 the Utility agreed to implement its “Land Conservation Commitment” (“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 2018, 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 “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

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

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. In January 2016, the CPUC closed the investigative proceedings. The total penalty included (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

The Utility refunded the $400 million to its customers in the second quarter of 2016 and paid the $300 million fine in the third quarter of 2015. On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The Utility is precluded from including these capital costs in rate base. The final phase two decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Federal Criminal Trial

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

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

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

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of December 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are Tellardin v. Anthony F. Earley, Jr.,. et al., Iron Workers Mid-South Pension Fund v. Johns, et al., and Bushkin v. Rambo et al.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated San Bruno Fire Derivative Cases pending conclusion of the federal criminal proceedings against the Utility. On November 16, 2016, counsel in the four consolidated San Bruno Fire Derivative cases, as well as counsel in the Tellardin action, appeared for a status conference in the San Mateo Superior Court. The court reaffirmed that all proceedings in these actions were stayed until the conclusion of the Utility's federal criminal proceeding, at which point they were directed to meet and confer and report back to the court. The parties completed a mediation session on December 8-9, 2016 and continue discussions about the potential resolution of the matter. These actions remain stayed.

Bushkin v. Rambo et al., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit Iron Workers Mid-South Pension Fund v. Johns, et al., discussed below. The plaintiff in the Bushkin lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the Bushkin plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility. On January 13, 2017, the parties submitted a joint case management statement advising the court that, because the Utility had not yet been sentenced, the case should remain stayed until at least March 10, 2017, when the parties will advise the court of further developments. While the Utility was sentenced in the federal criminal proceeding on January 26, 2017, this matter remains stayed until at least March 10, 2017.

The Iron Workers action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the San Bruno Fire Derivative Cases. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the San Bruno Fire Derivative Cases. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the federal criminal proceeding against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017. This matter remains stayed until at least March 15, 2017.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

Butte Fire Litigation

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

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

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

For additional information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Other Enforcement Matters

Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with electric and natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, and other enforcement matters. See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

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.

Subsequently, the California State Water Resources Control Board adopted a Once-Through Cooling Water Policy in May 2010 which requires Diablo Canyon to be in compliance with the policy by December 2024 and allows for alternative compliance measures at nuclear power plants.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. The Utility expects that the State Board’s OTC Policy and its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Water Board and the California Attorney General’s Office. Also, as required under the State Board’s OTC Policy, beginning in 2017, the Utility will pay an annual interim mitigation fee until operations cease at the end of the current licenses.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility's financial condition or results of operations.

Venting Incidents in San Benito County

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline must be released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County district attorney notified the Utility in December 2014 that it was contemplating bringing a civil legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. In January 2017, the Utility and the district attorney reached an agreement on a stipulated judgement that resolves the matter. The stipulated judgment includes a fine of approximately $175,000. In addition, a $75,000 fine will be held in abeyance for 5 years, and would be payable to the San Benito County district attorney in case of non-compliance with certain remedial requirements of the stipulated judgment. The stipulated judgment was executed by the court on January 27, 2017.

Transformer Oil Release in Sonoma County

During a rain storm in February 2015, transformer oil was released into an underground vault in the City of Santa Rosa, in Sonoma County, while a Utility crew was replacing a broken transformer. Following further rains, the oil released from the vault and reached a nearby creek. The event was investigated by Santa Rosa Fire Department, the local environmental enforcement authority, and later referred to the Sonoma County District Attorney's Office. In May 2016, the District Attorney informed the Utility that it would seek penalties and costs in excess of $100,000 for alleged violations of several sections of the California Health and Safety and California Government codes which prohibit unauthorized spills or releases of oil into waters of the state and require that releases be reported to the Office of Emergency Services. In November 2016, the Utility and the Sonoma County district attorney reached an agreement on a stipulated judgment that resolves the matter. The stipulated judgment includes a fine of $80,000, reimbursement of enforcement costs of $40,000, and injunctive provisions requiring improvements to the Utility's vault dewatering procedure and training. In November 2016, the court approved the stipulated judgment.

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 16, 2017. 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
Anthony F. Earley, Jr. (2)	67	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation	September 13, 2011 to present
		Executive Chairman of the Board, DTE Energy Company	October 1, 2010 to September 12, 2011
Nickolas Stavropoulos (2)	58	President, Gas	September 15, 2015 to present
		President, Gas Operations	August 17, 2015 to September 15, 2015
		Executive Vice President, Gas Operations	June 13, 2011 to August 16, 2015

Geisha J. Williams (2)	55	President, Electric	September 15, 2015 to present
		President, Electric Operations	August 17, 2015 to September 15, 2015
		Executive Vice President, Electric Operations	June 1, 2011 to August 16, 2015
Jason P. Wells	39	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
		Vice President, Finance	October 1, 2011 to July 31, 2013
John R. Simon	52	Executive Vice President, Corporate Services and Human Resources, PG&E Corporation	August 17, 2015 to present
		Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company	April 16, 2007 to August 16, 2015
Karen A. Austin	55	Senior Vice President and Chief Information Officer	June 1, 2011 to present
		President, Consumer Electronics, Sears Holdings	February 2009 to May 2011

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Desmond A. Bell (3)	54	Senior Vice President, Safety and Shared Services	January 1, 2012 to present
Helen A. Burt (3)	60	Senior Vice President, External Affairs and Public Policy, PG&E Corporation and Pacific Gas and Electric Company	September 30, 2015 to present
		Senior Vice President, Corporate Affairs, PG&E Corporation	September 18, 2014 to September 30, 2015
		Senior Vice President and Chief Customer Officer	February 27, 2006 to September 17, 2014
Loraine M. Giammona	49	Senior Vice President and Chief Customer Officer	September 18, 2014 to present
		Vice President, Customer Service	January 23, 2012 to September 17, 2014
		Regional Vice President, Customer Care, Comcast Cable	November 2002 to January 2012
Edward D. Halpin	55	Senior Vice President, Generation and Chief Nuclear Officer	March 28, 2016 to present
		Senior Vice President, Power Generation and Chief Nuclear Officer	September 8, 2015 to March 27, 2016
		Senior Vice President and Chief Nuclear Officer	April 2, 2012 to September 8, 2015
		President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company	December 2009 to March 2012
Patrick M. Hogan	53	Senior Vice President, Electric Operations	February 1, 2017 to present
		Senior Vice President, Electric Transmission and Distribution	March 1, 2016 to January 31, 2017
		Vice President, Electric Strategy and Asset Management	September 8, 2015 to February 29, 2016
		Vice President, Electric Operations, Asset Management	November 18, 2013 to September 7, 2015
		Senior Vice President, Transmission and Distribution Engineering and Design, BC Hydro	October 2011 to November 2013
Julie M. Kane	58	Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company	May 18, 2015 to present
		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
Steven E. Malnight	44	Senior Vice President, Regulatory Affairs	September 18, 2014 to present
		Vice President, Customer Energy Solutions	May 15, 2011 to September 17, 2014

		Vice President, Integrated Demand Side Management	July 1, 2010 to May 14, 2011
Dinyar B. Mistry	55	Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2017 to present

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		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
Hyun Park (4)	55	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
Jesus Soto, Jr.	49	Senior Vice President, Gas Operations	September 8, 2015 to present
		Senior Vice President, Engineering, Construction and Operations	September 16, 2013 to September 8, 2015
		Senior Vice President, Gas Transmission Operations	May 29, 2012 to September 15, 2013
		Vice President, Operations Services, El Paso Pipeline Group	May 2007 to May 2012
Fong Wan	55	Senior Vice President, Energy Policy and Procurement	September 8, 2015 to present
		Senior Vice President, Energy Procurement	October 1, 2008 to September 8, 2015
David S. Thomason	41	Vice President, Chief Financial Officer, and Controller	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
		Director, Planning, Forecasting and Reporting	October 3, 2011 to August 31, 2012

(1) Mr. Earley, Mr. Stavropoulos, Ms. Williams, Mr. Simon, Ms. Burt, Ms. Kane, Mr. Mistry, Mr. Park, and Mr. Wells are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.

(2) On November 14, 2016, the Board of Directors of PG&E Corporation elected Mr. Earley to the role of Executive Chair of the Board of PG&E Corporation and Ms. Williams to the role of Chief Executive Officer and President of PG&E Corporation, both effective March 1, 2017. Also on November 14, 2016, the Board of Directors of the Utility

elected Mr. Stavropoulos as President and Chief Operating Officer of the Utility effective March 1, 2017.

(3) Mr. Bell and Ms. Burt will step down from their positions effective March 1, 2017.

(4) Mr. Park will step down from his position effective March 1, 2017 but is expected to remain with PG&E Corporation until September 1, 2017.

PART II

ITEM 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

As of February 7, 2017, there were 56,835 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". The high and low closing prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. 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 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 and in "Liquidity and Financial Resources – Dividends" in Item 7 below.

Sales of Unregistered Equity Securities

PG&E Corporation made equity contributions to the Utility totaling $95 million during the quarter ended December 31, 2016. PG&E Corporation did not make any sales of unregistered equity securities during 2016 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, 2016, 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, 2016, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

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ITEM 6. SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2016	2015	2014	2013	2012
PG&E Corporation					
For the Year					
Operating revenues	$17,666	$16,833	$17,090	$15,598	$15,040
Operating income	2,177	1,508	2,450	1,762	1,693
Net income	1,407	888	1,450	828	830
Net earnings per common share, basic (1)	2.79	1.81	3.07	1.83	1.92
Net earnings per common share, diluted	2.78	1.79	3.06	1.83	1.92
Dividends declared per common share (2)	1.93	1.82	1.82	1.82	1.82
At Year-End					
Common stock price per share	$60.77	$53.19	$53.24	$40.28	$40.18
Total assets (3)	68,598	63,234	60,228	55,693	52,530
Long-term debt (excluding current portion) (3)	16,220	15,925	15,151	12,805	12,598
Capital lease obligations (excluding current portion) (4)	31	49	69	90	113
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$17,667	$16,833	$17,088	$15,593	$15,035
Operating income	2,181	1,511	2,452	1,790	1,695
Income available for common stock	1,388	848	1,419	852	797
At Year-End					
Total assets (5)	68,374	63,037	59,964	55,137	52,003
Long-term debt (excluding current portion) (5)	15,872	15,577	14,799	12,805	12,247
Capital lease obligations (excluding current portion) (4)	31	49	69	90	113

(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 MD&A in Item 7 and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 in Item 8.

(3) In accordance with ASU No. 2015-03, PG&E Corporation restated $105 million in 2015, $101 million in 2014, $88 million in 2013, and $81 million in 2012, of debt issuance costs. Total assets and total liabilities were each reduced by the amounts above with no impact to net income or total shareholders' equity previously reported.

(4) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

(5) In accordance with ASU No. 2015-03, the Utility restated $103 million in 2015, $99 million in 2014, $88 million in 2013, and $80 million in 2012, of debt issuance costs. Total assets and total liabilities were each reduced by the amounts above with no impact to net income or total shareholders' equity previously reported.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility's base revenue requirements are set by the CPUC in its GRC and GT&S rate case 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 and other employee 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 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.

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Summary of Changes in Net Income and Earnings per Share

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS based on earnings from operations) for the year ended December 31, 2016 compared to the year ended December 31, 2015 (see "Results of Operations" below). "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

(in millions, except per share amounts)	Earnings (1)	EPS (diluted)
Income Available for Common Shareholders - 2015	$ 874	$ 1.79
Add items impacting comparability:		
Fines and penalties	578	1.19
Pipeline-related expenses	61	0.13
Legal and regulatory related expenses	35	0.07
Natural gas matters insurance recoveries	(29)	(0.06)
Earnings from Operations - 2015 (2)	$ 1,519	$ 3.12
2015 GT&S revenue (3)	300	0.60
Growth in rate base earnings	102	0.20
Regulatory and legal matters	1	-
Gain on disposition of SolarCity stock (4)	(14)	(0.03)
Increase in shares outstanding	-	(0.09)
Miscellaneous	(24)	(0.04)
Earnings from Operations - 2016 (2)	$ 1,884	$ 3.76
Less items impacting comparability:		
Butte fire related costs (net of insurance) (5)	(137)	(0.27)
Fines and penalties (6)	(307)	(0.61)
Pipeline-related expenses (7)	(67)	(0.13)
Legal and regulatory related expenses (8)	(43)	(0.09)
GT&S capital disallowance (9)	(130)	(0.26)
GT&S revenue (10)	193	0.38
Income Available for Common Shareholders - 2016	$ 1,393	$ 2.78

(1) All amounts presented in the table above are tax-adjusted at PG&E Corporation's tax rate of 40.75% except for fines, which are not tax deductible. See footnote (6) below.

(2) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in footnotes (5) through (10).

(3) Represents the increase in 2016 revenues authorized December 1, 2016 in the final phase two decision of the Utility's 2015 GT&S rate case.

(4) Represents the gain recognized during the year ended December 31, 2015. No comparable gain was recognized in 2016.

(5) The Utility recorded costs of $232 million (before the tax impact of $95 million) during the year ended December 31, 2016 associated with the Butte fire, net of insurance. This includes accrued charges of $750 million (before the tax impact of $306 million) related to estimated third-party claims in connection with the Butte fire, partially offset by $625 million (before the tax impact of $255 million) as probable of insurance recovery. The Utility also incurred charges of $107 million (before the tax impact of $44 million) for Utility clean-up, repair, and legal costs associated with the Butte fire.

(6) The Utility incurred costs of $498 million (before the tax impact of $191 million), during the year ended December 31, 2016 associated with fines and penalties. This includes costs of $412 million (before the tax impact of $168 million) associated with safety-related cost disallowances imposed by the CPUC in its April 9, 2015 decision in the gas transmission pipeline investigations. The Utility also recorded $57 million (before the tax impact of $23 million) for disallowances imposed by the CPUC in its final phase two decision of the 2015 GT&S rate case for prohibited ex parte communications. In addition, the Utility accrued fines of $26 million in connection with the final decision approved by the CPUC on August 18, 2016 in its investigation regarding natural gas distribution record-keeping practices and $3 million in connection with the maximum statutory fine imposed on January 26, 2017 in the federal criminal trial against the Utility. These fines are not tax deductible. Future fines or penalties may be imposed in connection with other enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(7) The Utility incurred costs of $113 million (before the tax impact of $46 million), during the year ended December 31, 2016 for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights of way.

(8) The Utility incurred costs of $72 million (before the tax impact of $29 million), during the year ended December 31, 2016 for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(9) The Utility incurred charges of $219 million (before the tax impact of $89 million), during the year ended December 31, 2016, for disallowed capital expenditures based on the CPUC final phase one decision dated June 23, 2016 in the 2015 GT&S rate case, including $134 million (before the tax impact of $54 million) for the disallowed portion of the 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million (before the tax impact of $35 million) for the Utility's estimate of 2015 through 2018 capital expenditures that are likely to exceed authorized amounts. (See "Regulatory Matters" below for more information.)

(10) As a result of the timing of the CPUC's final phase two decision in the 2015 GT&S rate case, the Utility recorded $325 million (before the tax impact of $132 million) in excess of the 2016 authorized revenue requirement during the twelve months ended December 31, 2016.

Key Factors Affecting Financial Results

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

The Outcome of Enforcement, Litigation, and Regulatory Matters. The Utility's future financial results may continue to be impacted by the outcome of current and future enforcement, litigation, and regulatory matters, including the Butte fire litigation, potential costs associated with the alleged violations of the CPUC's ex parte communication rules, the cost of complying with the terms of probation and monitorship imposed in the sentencing phase of the federal criminal trial and related remedial and other measures, and potential penalties in connection with the Utility's self-report related to its customer service representatives' drug and alcohol testing program. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Timing and Outcome of Ratemaking Proceedings. The Utility's results may be impacted by the timing and outcome of its 2017 GRC, FERC TO rate case, and petition for modification related to its cost of capital. Based on the current schedule, the Utility expects a final decision in its 2017 GRC in the first half of 2017. (See "Regulatory Matters – 2017 General Rate Case" below for more information.) In addition, settlement negotiations are ongoing related to the Utility's FERC TO rate case requesting a 2017 retail electric transmission revenue requirement. (See "Regulatory Matters – FERC Transmission Owner Rate Cases" below for more information.) Also, on February 7, 2017, the Utility filed with the CPUC a petition for modification related to its cost of capital. (See "Regulatory Matters – CPUC Cost of Capital" below for more information.) The outcome of regulatory proceedings can be affected by many factors, including arguments made by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures. The Utility is committed to delivering safe, reliable, sustainable, and affordable electric and gas services to its customers. Increasing demands from state laws and policies relating to increased renewable energy resources, the reduction of GHG emissions, the expansion of energy efficiency programs, the development and widespread deployment of distributed generation and self-generation resources, and the development of energy storage technologies have increased pressure on the Utility to achieve efficiencies in its operations in order to maintain the affordability of its service. In any given year the Utility's ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2017 it will incur unrecovered pipeline-related expenses ranging from $80 million to $125 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the CPUC decision in the Utility's 2015 GT&S rate case establishes various cost caps that will increase the risk of overspend over the rate case cycle. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Amount and Timing of the Utility's Financing Needs. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In 2016, PG&E Corporation issued $842 million of common stock and used $835 million of the cash proceeds to make equity contributions to the Utility. PG&E Corporation forecasts that it will continue issuing a material amount of equity in future years, including $400 million to $600 million in 2017, primarily to support the Utility's capital expenditures. PG&E Corporation may issue additional equity to fund unrecoverable pipeline-related expenses and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances could have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2016 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 2016 Form 10-K. 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 not able 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 2016, 2015, and 2014. 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 available for common shareholders:

(in millions)	2016	2015	2014
Consolidated Total	$1,393	$874	$1,436
PG&E Corporation	5	26	17
Utility	$1,388	$848	$1,419

PG&E Corporation’s net income consists primarily of income taxes, interest expense on long-term debt, and other income from investments. Results include approximately $30 million and $45 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015 and 2014, respectively, with no corresponding gains in 2016.

Utility

The table below shows certain items from the Utility’s Consolidated Statements of Income for 2016, 2015, and 2014. 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 the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

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

(in millions)	2016 Revenues and Costs: That Impacted Earnings	2016 That Did Not Impact Earnings	2016 Total Utility	2015 Revenues and Costs: That Impacted Earnings	2015 That Did Not Impact Earnings	2015 Total Utility	2014 Revenues and Costs: That Impacted Earnings	2014 That Did Not Impact Earnings	2014 Total Utility
Electric operating revenues	$7,955	$5,910	$13,865	$7,442	$6,215	$13,657	$7,059	$6,597	$13,656
Natural gas operating revenues	2,767	1,035	3,802	2,082	1,094	3,176	2,072	1,360	3,432
Total operating revenues	10,722	6,945	17,667	9,524	7,309	16,833	9,131	7,957	17,088
Cost of electricity	-	4,765	4,765	-	5,099	5,099	-	5,615	5,615
Cost of natural gas	-	615	615	-	663	663	-	954	954
Operating and maintenance	5,787	1,565	7,352	5,402	1,547	6,949	4,247	1,388	5,635
Depreciation, amortization, and decommissioning	2,754	-	2,754	2,611	-	2,611	2,432	-	2,432
Total operating expenses	8,541	6,945	15,486	8,013	7,309	15,322	6,679	7,957	14,636
Operating income	2,181	-	2,181	1,511	-	1,511	2,452	-	2,452
Interest income (1)			22			8			8
Interest expense (1)			(819)			(763)			(720)
Other income, net (1)			88			87			77
Income before income taxes			1,472			843			1,817
Income tax provision (benefit) (1)			70			(19)			384
Net income			1,402			862			1,433
Preferred stock dividend requirement (1)			14			14			14
Income Available for Common Stock			$1,388			$848			$1,419

(1) These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2016, 2015, and 2014, 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 $1.2 billion or 13% in 2016 compared to 2015, primarily as a result of approximately $700 million of incremental revenues authorized in the 2015 GT&S rate case and approximately $425 million of additional base revenues as authorized by the CPUC in the 2014

GRC decision and by the FERC in the TO rate case.

The Utility included the authorized increase for the 2015 GT&S rate case period in rates starting August 1, 2016. The Utility will collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will recognize the remaining $102 million in the first quarter of 2017. (See “Regulatory Matters” below.)

The Utility’s electric and natural gas operating revenues that impacted earnings increased $393 million or 4% in 2015 compared to 2014, primarily as a result of approximately $490 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case. This increase was partially offset by the absence of approximately $110 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014.

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Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased $385 million or 7% in 2016 compared to 2015, primarily due to $857 million in charges for third-party claims, Utility clean-up, repair, and legal costs related to the Butte fire, $219 million in permanently disallowed capital spending (see "Regulatory Matters" below), $34 million in charges recorded in connection with the final CPUC decision related to the natural gas distribution facilities record-keeping investigation, the federal criminal trial, and the atmospheric corrosion inspection self-report, $24 million in higher pipeline-related expenses and legal and regulatory related expenses during the year ended December 31, 2016, an escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. These increases were partially offset by $500 million in charges associated with the Penalty Decision for customer refunds and fines incurred in 2015 with no corresponding charges in 2016 and approximately $125 million in lower disallowed capital charges associated with the Penalty Decision in 2016. Additionally, the Utility recorded approximately $625 million in probable insurance recoveries related to the Butte fire in the year ended December 31, 2016 as compared to $49 million of insurance recoveries for third-party claims related to the San Bruno accident for the same period in 2015. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's operating and maintenance expenses that impacted earnings increased $1.2 billion or 27% in 2015 compared to 2014, primarily due to $907 million in charges associated with the Penalty Decision, consisting of $400 million for the customer bill credit, an additional $100 million charge for the fine payable to the state, and $407 million of disallowed capital charges. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The increase is also due to higher labor and benefit-related expenses of approximately $100 million and fewer insurance recoveries for third-party claims and associated legal costs of $63 million related to the San Bruno accident. No further insurance recoveries related to these claims are expected. These increases were offset by $116 million in disallowed capital recorded in 2014 related to the PSEP.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased $143 million or 5% in 2016 compared to 2015 and $179 million or 7% in 2015 compared to 2014. In 2016, the increase was primarily due to the impact of capital additions. In 2015, the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the FERC in the TO rate case.

Interest Expense

The Utility's interest expenses increased by $56 million or 7% in the year ended December 31, 2016 compared to the same period in 2015, primarily due to the issuance of additional long-term debt. The Utility's interest expenses increased by $43 million or 6% in the year ended December 31, 2015 compared to the same period in 2014, primarily due to the issuance of long-term debt.

Interest Income and Other Income, Net

There were no material changes to interest income and other income, net for the periods presented.

Income Tax Provision

The Utility's income tax provision increased $89 million, or 468%, in 2016 as compared to 2015. The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 2016 compared to 2015, partially offset by higher tax benefits from property-related timing differences in 2016 compared to 2015. The higher effective tax rate is driven by higher pre-tax earnings in 2016, partially offset by rate impact from property-related timing differences.

The Utility's income tax provision decreased $403 million, or 105%, in 2015 as compared to 2014. This is primarily the result of the statutory tax effect of lower pre-tax income and higher tax benefits from property-related timing differences in 2015 as compared to 2014. The lower effective tax rate in 2015 is the result of lower pre-tax earnings in 2015 and rate impact from property-related timing differences.

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

	2016		2015		2014	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	(2.2)		(4.8)		1.6	
Effect of regulatory treatment of fixed asset differences (2)	(23.4)		(33.7)		(14.7)	
Tax credits	(0.8)		(1.3)		(0.7)	
Benefit of loss carryback	(1.1)		(1.5)		(0.8)	
Non-deductible penalties (3)	0.8		4.3		0.3	
Other, net (4)	(3.5)		(0.2)		0.4	
Effective tax rate	4.8	%	(2.2)	%	21.1	%

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

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted only 2016. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.

(3) Primarily represents the effects of non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for the year ended December 31, 2016 and the effects of the Penalty Decision for the year ended December 31, 2015. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

(4) In 2016, the amount primarily represents the impact of tax audit settlements.

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 detail.

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.)

(in millions)	2016	2015	2014
Cost of purchased power	$4,510	$4,805	$5,266
Fuel used in own generation facilities	255	294	349
Total cost of electricity	$4,765	$5,099	$5,615
Average cost of purchased power per kWh (1)	$0.109	$0.100	$0.101
Total purchased power (in millions of kWh) (2)	41,324	48,175	52,008

(1) Cost of purchased power was impacted primarily by a higher percentage of renewable energy resources.

(2) The decrease in purchased power primarily resulted from an increase in generation from the Utility's Diablo Canyon nuclear power plant and its hydroelectric facilities as well as lower electric customer demand.

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.

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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)	2016	2015	2014
Cost of natural gas sold	$481	$518	$813
Transportation cost of natural gas sold	134	145	141
Total cost of natural gas	$615	$663	$954
Average cost per Mcf of natural gas sold	$2.45	$2.74	$4.37
Total natural gas sold (in millions of Mcf)	196	189	186

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 2016, 2015, and 2014, no material amounts were incurred above authorized amounts.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock. (See "Ratemaking Mechanisms" in Item 1.) The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability positions. (See Notes 9 and 13 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue between $400 million and $600 million in common stock during 2017, primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by the timing and outcome of unrecoverable pipeline-related expenses and by fines, penalties and claims that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below. Common stock issuances by PG&E Corporation to fund these needs could have a material dilutive impact on PG&E Corporation's EPS.

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. In addition to cash and cash equivalents, the Utility holds restricted cash that, prior to October 2016, primarily consisted of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility’s reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. In October 2016, the Utility received approval from the bankruptcy court to release the remaining $161 million of cash held in escrow to unrestricted cash for use by the Utility. (See “Resolution of Remaining Chapter 11 Disputed Claims” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Financial Resources

Debt and Equity Financings

The Utility issued $1.0 billion in long-term debt and $500 million in short-term debt during the year ended December 31, 2016. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

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

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

In addition, during 2016, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $364 million.

The proceeds from equity issuances were used for general corporate purposes, including the contribution of equity to the Utility. For the year ended December 31, 2016, PG&E Corporation made equity contributions to the Utility of $835 million. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2017.

Revolving Credit Facilities and Commercial Paper Programs

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. At December 31, 2016, PG&E Corporation and the Utility had $300 million and $1.9 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. For the year ended December 31, 2016, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $84 million and $837 million, and a maximum outstanding balance of $176 million and $1.4 billion, respectively. At December 31, 2016, the Utility had an outstanding commercial paper balance of $1.0 billion and PG&E Corporation did not have any commercial paper outstanding. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 50%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In May 2016, the Board of Directors of PG&E Corporation and the Utility each adopted a new target dividend payout ratio range of 55% to 65% of earnings, with a target to reach a payout ratio of approximately 60% by 2019. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

PG&E Corporation

For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. In May 2016, the Board of Directors of PG&E Corporation declared a new quarterly common stock dividend of $0.49 per share. As a result, for each of the second, third and fourth quarters of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share. In 2016, total dividends were $1.925 per share. For each of the quarters in 2015 and 2014, the Board of Directors of PG&E Corporation declared common stock dividends of $0.455 per share, for annual dividends of $1.82 per share. Dividends paid to common shareholders by PG&E Corporation were $921 million in 2016, $856 million in 2015, and $828 million in 2014. In December 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.49 per share, totaling $248 million, of which approximately $243 million was paid on January 15, 2017 to shareholders of record on December 30, 2016.

Utility

For the first quarter of 2016, the Board of Directors of the Utility declared a common stock dividend of $179 million to PG&E Corporation. For each of the second, third and fourth quarters of 2016, the Board of Directors of the Utility declared common stock dividends of $244 million to PG&E Corporation. In 2016, total dividends paid by the Utility to PG&E Corporation were $911 million. For each of the quarters in 2015 and 2014, the Board of Directors of the Utility declared common stock dividends of $179 million to PG&E Corporation for annual dividends paid of $716 million in 2015 and 2014. In addition, the Utility paid $14 million of dividends on preferred stock in each of 2016, 2015, and 2014. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends. In December 2016, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on February 15, 2017, to shareholders of record on January 31, 2017.

Utility Cash Flows

The Utility’s cash flows were as follows:

	Year Ended December 31,		
(in millions)	2016	2015	2014
Net cash provided by operating activities	$4,344	$3,747	$3,632
Net cash used in investing activities	(5,526)	(5,211)	(4,799)
Net cash provided by financing activities	1,194	1,468	1,157
Net change in cash and cash equivalents	$12	$4	$(10)

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 2016, net cash provided by operating activities increased by $597 million compared to 2015. This increase was partially due to the Utility receiving an additional $170 million in tax refunds in 2016 than in 2015. The remaining increase was primarily due to fluctuations in activities within the normal course of business such as timing and amount of customer billings and vendor billings and payments. During 2015, net cash provided by operating activities increased by $115 million compared to 2014. This increase was primarily due to higher base revenue collections authorized in the 2014 GRC and lower purchased power costs (see “Cost of Electricity” under “Results of Operations – Utility Revenues and Costs that did not Impact Earnings” above), offset by the payment of a $300 million fine to the State General Fund as required by the Penalty Decision.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and outcome of ratemaking proceedings, including the 2017 GRC and the TO rate case, and cost of capital proceeding;
- the timing and amounts of costs that may be incurred in connection with claims associated with Butte fire and the timing and amount of related insurance recoveries, fines or penalties that may be imposed in connection with the ex parte OII or costs in connection with a potential settlement, fines or penalties that may be imposed in connection with other enforcement and litigation matters, costs associated with the terms of probation and monitorship imposed in the sentencing phase of the federal criminal trial, and potential remedial and other measures that could be imposed on the Utility in connection with the DOI debarment proceeding (see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below);
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system;
- the timing and amount of tax payments (including the bonus depreciation), tax refunds, net collateral payments, and interest payments, as well as changes in tax regulations that could be adopted by Congress as a result of the new federal administration and other proposals; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

Investing Activities

Net cash used in investing activities increased by $315 million during 2016 as compared to 2015 primarily due to an increase of approximately $440 million in capital expenditures, partially offset by an increase in restricted cash released from escrow by approximately $160 million. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) Net cash used in investing activities increased by $412 million during 2015 as compared to 2014 primarily due to an increase of $340 million in capital expenditures and an increase in net purchases of nuclear decommissioning trust investments in 2015 as compared to net proceeds associated with sales of nuclear decommissioning trust investments in 2014.

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 $6.0 billion in capital expenditures in each of the years 2017, 2018, and 2019.

Financing Activities

During 2016, net cash provided by financing activities decreased by $274 million as compared to 2015. During 2015, net cash provided by financing activities increased by $311 million as compared to 2014. 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 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, 2016:

	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):	$1,495	$ 2,408	$ 3,328	$ 22,452	$ 29,683
Purchase obligations (2):					
Power purchase agreements:	3,417	6,175	5,844	29,506	44,942
Natural gas supply, transportation, and storage	536	329	241	455	1,561
Nuclear fuel agreements	97	188	179	136	600
Pension and other benefits (3)	388	776	776	388	2,328
Operating leases (2)	44	80	75	168	367
Preferred dividends (4)	14	28	28	-	70
PG&E Corporation					
Long-term debt (1):	8	362	-	-	370
Total Contractual Commitments	$5,999	$ 10,346	$ 10,471	$ 53,105	$ 79,921

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2016 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

(2) See "Purchase Commitments" and "Other Commitments" in Note 13 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) Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

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.

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 in Note 13 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) 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 Note 13 of the Notes to the Consolidated Financial Statements in Item 8. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results.

Butte Fire Litigation

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

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On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

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

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

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of $750 million accrued through December 31, 2016 but is currently unable to reasonably estimate the upper end of the range of losses because it is still in an early stage of the evaluation of claims, the mediation and settlement process, and discovery. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. Such insurance coverage is subject to the terms and limitations of the applicable policies and may not be sufficient to cover the Utility's ultimate liability.

The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. The Utility has recorded $625 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility is pursuing coverage under the insurance policies of its two vegetation management contractors, including under policies where the Utility is listed as an additional insured. Recoveries of any amounts under these policies are uncertain. If the ultimate liability exceeds the amounts recovered through insurance, the Utility would expect to seek authorization from the CPUC and the FERC to recover any excess amounts from customers. The Utility is unable to predict the timing or outcome of any such proceeding, or the timing of recovery from customers, if any. The resolution of claims, any future regulatory proceeding, and the recoveries from other potentially responsible parties and customers could extend over a number of years. (For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Department of Interior Inquiry

In September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the San Bruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. The Utility filed its initial response on November 2, 2015 to demonstrate that it is a "presently responsible" contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. On April 8, 2016, the Utility received a series of follow-up questions from the DOI regarding its November 2015 submission. On November 21, 2016, the Utility provided the DOI with a supplemental submission in which it addressed the DOI's April 8, 2016 questions. The Utility continues to fully cooperate with the DOI.

As a result of the August 9, 2016 jury's verdict in the federal criminal trial, the Utility updated its registration on the federal government's System for Award Management (SAM), a federal procurement database, to reflect the verdict. Under federal law, the government may not enter into a contract with any corporation that was convicted of a felony criminal violation under any federal law within the preceding 24 months, where the awarding agency is aware of the conviction, unless an agency has considered suspension or debarment of the corporation and made a determination that this action is not necessary to protect the interests of the government.

On December 21, 2016, the Utility and the DOI entered into an interim administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect federal government's business interests. The agreement will be effective until superseded by an amended agreement or determination. The agreement also provides that the DOI is still conducting a review to determine whether the Utility has an effective compliance and ethics program and that the DOI is required to use its best efforts to complete its review before the end of 2017. If the DOI determines that the Utility's program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s).

The Utility could incur material costs, not recoverable through rates, to implement remedial and other measures that could be imposed, the amount of which the Utility is currently unable to estimate.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of December 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are Tellardin v. Anthony F. Earley, Jr.,. et al., Iron Workers Mid-South Pension Fund v. Johns, et al., and Bushkin v. Rambo et al.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated San Bruno Fire Derivative Cases pending conclusion of the federal criminal proceedings against the Utility. On November 16, 2016, counsel in the four consolidated San Bruno Fire Derivative cases, as well as counsel in the Tellardin action, appeared for a status conference in the San Mateo Superior Court. The court reaffirmed that all proceedings in these actions were stayed until the conclusion of the Utility's federal criminal proceeding, at which point they were directed to meet and confer and report back to the court. The parties completed a mediation session on December 8-9, 2016 and continue discussions about the potential resolution of the matter. These actions remain stayed.

Bushkin v. Rambo et al., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit Iron Workers Mid-South Pension Fund v. Johns, et al., discussed below. The plaintiff in the Bushkin lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the Bushkin plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff’s claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff’s petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the court to dismiss plaintiff’s petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation’s motion, and indicated that plaintiff’s petition was stayed pending resolution of the criminal matter against the Utility. On January 13, 2017, the parties submitted a joint case management statement advising the court that, because the Utility had not yet been sentenced, the case should remain stayed until at least March 10, 2017, when the parties will advise the court of further developments. While the Utility was sentenced in the federal criminal proceeding on January 26, 2017, this matter remains stayed until at least March 10, 2017.

The Iron Workers action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the San Bruno Fire Derivative Cases. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court’s request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the San Bruno Fire Derivative Cases. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the federal criminal proceeding against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017. This matter remains stayed until at least March 15, 2017.

For more information about the federal criminal proceeding, see Note 13 of the Notes to the Consolidated Financial Statements and Item 3 Legal Proceedings.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

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 these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

2017 General Rate Case

On September 1, 2015, the Utility filed its 2017 GRC application with the CPUC. On August 3, 2016, the Utility, together with ORA, TURN, and 12 other intervening parties filed a motion with the CPUC seeking approval of a settlement agreement that resolves nearly all of the issues raised by the parties in the Utility's 2017 GRC. All parties who filed testimony in the case joined the settlement agreement, which was the subject of a one-day workshop overseen by the assigned commissioner and ALJ. The settlement agreement will ultimately be considered by the full commission. In the GRC proceeding, the CPUC will determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 or 2020 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 revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.)

Revenue Requirements and Attrition Year Revenues

The settlement agreement proposed that the Utility's 2016 authorized revenue requirement of $7.9 billion be increased by $88 million, effective January 1, 2017. The settlement agreement further proposed an increase to the authorized 2017 revenues of $444 million in 2018 and an additional increase of $361 million in 2019, as shown in the table below.

The settlement agreement identified two contested issues. First, the parties were unable to agree on whether there should be a third post-test year or "attrition" year for this GRC cycle. ORA and the Utility recommend a third post-test year for this cycle that would provide for an additional increase of $361 million in 2020. TURN and certain other settling parties oppose the third post-test year. The other contested issue concerns whether the Utility should be authorized to establish a new balancing account for costs arising from the CPUC's rulemaking on natural gas leak abatement. The Utility and certain settling parties support the balancing account. TURN and certain other settling parties do not. ORA does not oppose it. Interested parties filed comments and reply comments on the contested issues and these issues were also discussed at a one-day workshop on August 30, 2016.

The table below summarizes the differences between the amount of revenue requirement increases included in the Utility's request, as updated in the Utility's supplemental testimony filed on February 22, 2016 and its May 27, 2016 rebuttal testimony, and the amount proposed in the settlement agreement:

Year	Increase Requested in GRC Application (in millions)	Increase Proposed in Settlement Agreement (in millions)	Difference(1) (Decrease from GRC Application) (in millions)
2017	$319	$88	$(231)
2018	467	444	(23)
2019	368	361	(7)
2020(2)	N/A	361	N/A

(1) Rounded for presentation purposes.

(2) Whether or not revenues should be authorized for 2020 is a contested issue.

The following table shows the difference between the Utility's requested increases in 2017 revenue requirements by line of business and the amounts proposed in the settlement agreement:

(in millions) Line of Business:	Increase Requested in GRC Application			Increase/(Decrease) Proposed in Settlement Agreement			Difference(1) (Decrease from GRC Application)
Electric distribution	$67	1.6	%	$(62)	(1.5)	%	$(128)
Gas distribution	59	3.4		(3)	(0.2)		(62)
Electric generation	193	9.9		153	7.8		(40)
2017 revenue requirement increases	$319	4.0	%	$88	1.1	%	$(231)

(1) Rounded for presentation purposes.

The following table shows the differences, by line of business and cost category, between the amount of revenue requirements included in the GRC application and the amount proposed in the settlement agreement, as well as the differences between the 2016 authorized revenue requirements and (i) the GRC application and (ii) the amounts proposed in the settlement agreement:

(in millions) (1) Line of Business:	Amounts Requested in 2017 GRC Application	Amounts Proposed in Settlement Agreement	Difference (Decrease)	Increase/ (Decrease) 2016 Amounts vs. 2017 GRC Application	Increase/ (Decrease) 2016 Amounts vs. Settlement Agreement
Electric distribution	$ 4,279	$ 4,151	$ (128)	$ 67	$ (62)
Gas distribution	1,801	1,738	(62)	59	(3)
Electric generation	2,155	2,115	(40)	193	153
Total revenue requirements	$ 8,235	$ 8,004	$ (231)	$ 319	$ 88
Cost Category: (in millions) (1)					
Operations and maintenance	$ 1,825	$ 1,794	$ (31)	161	131
Customer services	361	334	(27)	42	15
Administrative and general	975	912	(62)	(36)	(99)
Less: Revenue credits	(140)	(152)	(12)	(9)	(21)
Franchise fees, taxes other than income, and other adjustments	184	170	(14)	146	132
Depreciation (including costs of asset removal), return, and income taxes	5,030	4,946	(84)	15	(70)
Total revenue requirements	$ 8,235	$ 8,004	$ (231)	$ 319	$ 88

(1) Rounded for presentation purposes.

The settlement agreement proposed reductions in the following areas forecast in the GRC application. For gas distribution, reductions are proposed for corrosion control, leak management, gas operations technology, and new business. For electric distribution, reductions are proposed for overhead maintenance, capacity, technology, mapping and records, reliability, substation management, new business, and undergrounding work. For electric distribution, the capital-related reductions are offset in part by increases in the replacement and installation of additional units in specific asset areas. For electric generation, the settlement agreement proposed to move costs related to Diablo Canyon seismic studies from the GRC to the Utility's Energy Resource Recovery Account proceeding. Proposed reductions in the customer service area largely relate to the removal of certain costs from the forecast related to residential rate reform implementation. Some of these costs would be recoverable through the existing Residential Rates Reform Memorandum Account, and the Utility could seek recovery of the remaining costs in a future filing with the CPUC. Additionally, a number of company-wide reductions, including reductions to the Short-Term Incentive Plan and certain employee benefits, are proposed in the settlement agreement.

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Balancing Accounts

The settlement agreement proposes to retain certain existing balancing accounts, including the Tax Act Memo Account that was first established following the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, and to eliminate certain memorandum and balancing accounts that are no longer necessary. In addition to the contested balancing account for natural gas leak abatement mitigation costs, the settlement agreement proposes one new tax-related memorandum account to track the impact on the revenue requirement from certain types of changes in tax laws or regulations.

Capital Additions and Rate Base

The settlement agreement proposes capital expenditures of $3.9 billion for 2017 for the portions of the Utility's business addressed in the GRC. Proposed capital expenditures are lower than the amount included in the GRC application of $4.0 billion for 2017, consistent with the provisions of the settlement agreement. While the settlement agreement proposes overall revenue requirement increases for 2018 and 2019, it does not specify capital expenditures for those years. At the August 30, 2016 workshop, the Utility estimated authorized capital expenditures of $3.6 billion for 2018 and $3.5 billion for 2019, based on a calculation method that is subject to CPUC approval, as compared to its request of approximately $4.0 billion each year. The Utility is unable to predict if the CPUC will approve its proposed calculation method.

The settlement agreement proposes a 2017 weighted average rate base of $24.3 billion for the portions of the Utility's business reviewed in the GRC, compared with the Utility's request of $24.5 billion. The $200 million difference is primarily due to the lower level of capital expenditures agreed to in the settlement. At the August 30, 2016 workshop, the Utility also estimated a weighted average rate base of $25.4 billion for 2018 and $26.3 billion for 2019, compared with the Utility's request of $25.7 billion and $26.9 billion, respectively.

Evidentiary hearings were held on September 1, 2016. A workshop was held on January 11, 2017 to further explore the three-year versus four-year rate case cycle. Under the current schedule, a final CPUC decision is expected to be issued in the first half of 2017. On March 17, 2016, the CPUC issued a decision to allow the authorized revenue requirement changes to become effective on January 1, 2017, even if the final decision is issued after that date.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the settlement agreement.

2015 Gas Transmission and Storage Rate Case

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility's 2015 GT&S rate case. The decision adopts the revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (see table below). The decision authorizes the Utility to collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will complete recording $102 million of the retroactive revenue requirement increase in the first quarter of 2017.

The phase one decision excludes from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallows $120 million of that amount and orders that the remaining $576 million be subject to a third party audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also establishes various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way capital balancing accounts. In the second quarter of 2016, the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This includes $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. The Utility took an additional charge of $29 million in the fourth quarter of 2016 related to 2015 through 2018 capital expenditures that are forecasted to exceed authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.

The phase one decision denies the Utility's request for full balancing account treatment for recovery of authorized transportation and storage revenue requirements for non-core customers, and instead continues the revenue sharing mechanism authorized in the 2011 GT&S rate case that subjects a portion of the Utility's transportation and storage revenue requirement to market risk.

The phase one decision also authorizes the Utility's request for cost recovery of up to $157 million for the construction of Line 407, a 25.5 mile, 30-inch pipeline in the Sacramento Valley expected to be built during this rate case period. The authorized revenue requirements will begin when Line 407 becomes operational. The decision also authorizes the Utility to track costs exceeding $157 million in a memorandum account. A reasonableness review of all costs for Line 407 will take place in the next GT&S rate case.

On August 1, 2016, TURN, ORA, and Indicated Shippers filed an application for rehearing of the phase one decision. The application indicates that the decision contains language suggesting that the authorized revenue requirement is to comply with new federal and state safety mandates and should be removed from the final decision, allows recovery of shareholder costs in rates, and improperly sequences the calculation of the San Bruno Penalty and the ex parte disallowance. The Utility filed a response on August 16, 2016. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the parties' recommendations.

On December 1, 2016, the CPUC approved a final decision in phase two of the Utility's 2015 GT&S rate case, regarding the $850 million penalty assessed in the Penalty Decision. The final phase two decision applies $689 million of the $850 million penalty (81 percent) to capital expenditures and the remaining $161 million (19 percent) to expenses, and then reduces the 2015 revenue requirement by $72 million for the five-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding ($57 million of the $72 million total ex parte disallowance was recognized in 2016 and the remaining $15 million will be recognized in the first quarter of 2017). The final decision also approves the Utility's list of programs which meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

The following table shows the revenue requirement amounts adopted in the Utility's 2015 GT&S rate case including adjustments for the $850 million Penalty Decision disallowance and the ex parte disallowance:

(in millions)	2015	2016	2017	2018
Revenue Requirement Before Adjustments	$ 1,046	$ 1,110	$ 1,220	$ 1,324
San Bruno Penalty Expense Allocation	(161)			
San Bruno Penalty Capital Revenue Requirement Allocation	5	(47)	(93)	(93)
Other Expense Adjustments	(3)	(2)	(2)	(1)
Adjusted Ex Parte Penalty	(72)			
Final Phase Two Revenue Requirement	$ 815	$ 1,061	$ 1,125	$ 1,230

The final phase two decision adopts total weighted average rate base of $2.8 billion in 2015, $2.8 billion in 2016, $3.0 billion in 2017, and $3.5 billion in 2018. The final phase two decision reduces rate base by the full amount of the disallowed capital expenditures but does not remove the associated deferred taxes, which the Utility believes creates a normalization violation. In the final decision, the CPUC authorizes the Utility to establish a Tax Normalization Memorandum Account to track relevant costs and clarifies that it does not intend the rate base offset or the penalty generally, to create tax timing differences. The final decision also affirms the CPUC's intention to comply with normalization rules and to avoid the potential adverse consequences of a finding of a normalization violation by the IRS. Pursuant to the final phase two decision, on February 6, 2017, the Utility submitted an advice letter to the CPUC to provide 30 days advance notice of the Utility's request to the IRS for a private letter ruling to determine whether the adopted rate base offset complies with IRS normalization rules. The final decision authorizes the Utility to subsequently seek an appropriate adjustment to its revenue requirements and rate base if the IRS finds a normalization violation.

On January 4, 2017, TURN, ORA and Indicated Shippers filed an application for rehearing of the phase two decision. Specifically, the application argues that the decision inappropriately sequenced the San Bruno Penalty and the ex parte ratemaking disallowance. The Utility filed a response on January 19, 2017. The Utility cannot predict when or if the CPUC will grant the rehearing.

With the addition of a third attrition year, the Utility's next GT&S cycle will begin in 2019. The decision requires the Utility to file its next GT&S application in 2017.

FERC Transmission Owner Rate Cases

On July 29, 2015, the Utility requested a 2016 retail electric transmission revenue requirement of $1.515 billion, a $314 million increase over the previous year's authorized revenue requirement of $1.201 billion. The Utility's proposed rates went into effect on March 1, 2016, subject to refund, and pending a final decision by the FERC. On September 1, 2016, the Utility and other settling parties (including the CPUC) filed a motion at the FERC for approval of a settlement proposing that the Utility's 2016 retail electric transmission revenue requirement be set at $1.331 billion, a $130 million increase over the previous year's authorized revenue requirement. The Utility also filed a motion on September 1, 2016, requesting the implementation of interim rates, which was an agreed upon term of the settlement. The motion was granted and, as a result, the interim rates became effective for wholesale customers on September 1, 2016 and for retail customers on October 1, 2016. The FERC approved the settlement on November 17, 2016.

On July 29, 2016, the Utility filed a rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.718 billion, a $387 million increase over the 2016 revenue requirement of $1.331 billion. The forecasted network transmission rate base for 2017 is $6.7 billion. The Utility is also 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 will make investments of $1.296 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 settlement negotiations. The order set an effective date for rates of March 1, 2017, and made the rates subject to hearing and refund. The next settlement conference is scheduled for March 16 and March 17, 2017.

CPUC Cost of Capital

On February 6, 2017, the Utility and other California IOUs entered into a MOU with the CPUC, ORA, and TURN to extend the next cost of capital application filing deadline two years to April 22, 2019 for the year 2020. To implement the MOU, on February 7, 2016, the IOUs, ORA, and TURN filed with the CPUC a petition for modification of prior CPUC decisions addressing the cost of capital. If the petition for modification is approved as submitted it would reduce the Utility's ROE from 10.40% to 10.25% and reset the Utility's authorized cost of long-term debt and preferred stock beginning January 1, 2018. The long-term debt cost reset will reflect actual embedded costs as of the end of August 2017 and forecasted interest rates for the new long-term debt scheduled to be issued for the remainder of 2017 and all of 2018. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity would remain unchanged.

If and once the petition for modification is granted by the CPUC, each IOU will submit to the CPUC in September 2017 its respective updated cost of capital and corresponding revenue requirement impacts with an effective date of January 1, 2018. While the actual changes to the Utility's revenue requirement resulting from the petition for modification will not be known until the Utility's filing in September 2017, the Utility estimates that its annual revenue requirement will be reduced by approximately $100 million, beginning in 2018. These estimates are based on current and forecasted market interest rates. Changes in market interest rates can have material effects on the cost of the Utility's future financings and consequently on the estimated change in annual revenue requirements.

The Utility's cost of capital adjustment mechanism would not operate in 2017 but could operate in 2018 to change the cost of capital for 2019. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the existing terms of the mechanism. Concurrently with the petition for modification, the Utility and other California IOUs sent a letter to the executive director of the CPUC requesting that the existing April 2017 filing due date for the 2018 cost of capital be deferred while the CPUC is considering the petition for modification. On February 13, 2017, the executive director of the CPUC granted the request. As extended, the Utility and the other California IOUs would file their next cost of capital applications 60 days after the effective date of the CPUC decision on the petition for modification, or April 20, 2017, whichever is later, if the CPUC does not grant the petition for modification. The Utility expects that the CPUC may issue a decision in the first half of 2017.

Diablo Canyon Nuclear Power Plant

Joint Proposal for Plant Retirement

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application implements a joint proposal between the Utility and the Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility.

The application and joint proposal include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. The parties to the joint proposal proposed that the Utility be authorized to procure GHG-free replacement resources in three competitive procurement tranches: in Tranche 1, the Utility would be authorized to obtain 2,000 gross GWh of energy efficiency savings to be implemented over the 2018 to 2024 time period; in Tranche 2, the Utility would be authorized to procure through a solicitation 2,000 GWh of GHG-free energy resources that will commence energy deliveries or add energy efficiency projects to the system in the 2025 to 2030 time period; and in Tranche 3, the Utility would commit to a voluntary 55% RPS beginning in 2031, and would maintain this voluntary commitment through 2045 or until superseded by action of the state legislature or the CPUC. The three tranches of resource procurement in the application and joint proposal are not intended to specify all energy resources that will be needed to ensure the orderly replacement of Diablo Canyon. Instead, the Utility expects that the full solution will be addressed in ongoing CPUC proceedings.

Costs associated with energy efficiency projects or programs in Tranche 1 and Tranche 2 would be recovered through the Utility's electric public purpose program rates as non-bypassable charges, consistent with the existing recovery mechanisms for energy efficiency program costs. GHG-free energy resources costs from Tranche 2 are proposed to be recovered through a non-bypassable cost allocation mechanism called the Clean California Charge that (1) equitably allocates costs and benefits, such as RPS or Resource Adequacy credits, associated with the procurement among responsible load-serving entities, and (2) determines the net capacity costs of such procurement consistent with the methodology for the allocation of net capacity costs laid out by the CPUC. Costs associated with procurement for Tranche 3 would be recovered through a separate renewable non-bypassable charge.

The application seeks confirmation from the CPUC that the Utility's full investment in Diablo Canyon and authorized rate of return will be recovered in rates by the time the facility ceases operations. Additionally, the Utility requests that the CPUC pre-approve the recovery of certain costs related to the closure of the Diablo Canyon. These include the non-bypassable cost allocation mechanism for procurement of GHG-free energy and the recovery of $1.3 billion for administration and acquisition of the new Tranche 1 energy efficiency procurement as authorized energy efficiency funding, subject to return of all unspent funds; the recovery of employee retention and retraining and development programs to continue safe and efficient operation of Diablo Canyon through the end of its license periods, estimated at approximately $360 million; and a community mitigation program to compensate San Luis Obispo County for the decline in local economic stimulus provided by Diablo Canyon through a transition period ending in 2025, estimated at $85 million. The Utility also seeks cost recovery of approximately $50 million in costs related to the federal and state Diablo Canyon license renewal process.

More than 40 parties have submitted responses and protests to the Utility's application. A prehearing conference on the application was held on October 6, 2016 and public participation hearings were held in San Luis Obispo on October 20, 2016. On November 18, 2016, a scoping memo was issued that set the schedule and determined that land issues would be out of the scope of this proceeding. In December 2016, the Utility filed with the CPUC the community impact mitigation program settlement agreement of $85 million, compared to $50 million included in the original joint proposal filed on August 11, 2016. Intervenor testimonies were submitted to the CPUC in January 2017. Several intervenors indicated their support to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025. Several parties argued, however, that a component of the employee retention program and community impact mitigation program be funded by shareholders. Several intervenors also submitted proposals for modifications to certain aspects of the three GHG-free replacement tranches. Several parties recommended that the license renewal project cost recovery request be rejected and/or be paid for by both customers and shareholders. There were no direct challenges to the Diablo Canyon remaining net book value cost recovery proposal. Rebuttal testimony and comments on the community impact mitigation program settlement agreement are scheduled to be submitted to the CPUC on March 17, 2017 and evidentiary hearings are scheduled to take place in April 2017. Opening and reply briefs are due on May 26, 2017 and June 9, 2017, respectively. The Utility expects that a final decision will be issued by the end of 2017. Upon CPUC approval of the application and such approval becoming final and non-appealable, the Utility will withdraw its license renewal application currently pending before the NRC. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the application.

California State Lands Commission Lands Lease

On June 28, 2016, California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon's current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the new lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 20 years. On August 28, 2016, the World Business Academy (WBA) filed a writ in the Los Angeles Superior Court. WBA asserts that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act. If the petitioner prevails in its challenge, the State Lands Commission could be required to perform an environmental review of the new lands lease. The court has set a trial date of July 11, 2017, with the petitioner's opening brief due February 27, 2017, opposition briefs due April 24, 2017, and reply briefs due May 22, 2017.

Asset Retirement Obligations

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 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.

On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion, for a total estimated cost of $4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the joint proposal's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program described above. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019.

On July 15, 2016, the assigned CPUC commissioner and ALJ issued a scoping memo for the Utility's 2015 NDCTP and excluded from the scope of the proceeding the issue on whether the Utility should be required to present additional analysis for a license extension scenario for Diablo Canyon, as a result of the Utility's announcement of its plan to not seek relicensing of Diablo Canyon beyond its current operating authority. The scoping memo also adopts within the scope of the proceeding a reasonableness review of the Utility's estimated updated cost to decommission the Utility's nuclear power plants and of the forecasts of certain expenses and the decommissioning trust funds' rates of return. Evidentiary hearings took place in September 2016 and opening briefs were submitted on October 14, 2016. Intervenor parties proposed several major recommendations including a reduction to the total spent nuclear fuel storage forecast, a reduction to the large component (reactor vessels, steam generators, and other large plant components) removal cost estimate, and a reduction to the waste disposal estimate. Additionally, intervenors asserted that the CPUC should not permit the Utility to increase its Diablo Canyon-related revenue requirement at this time as it has not demonstrated its current estimate is reasonable. Parties also claimed that the Utility has not justified its increase to security costs and decommissioning oversight contractor staff costs. No party challenged the Utility's decommissioning trust funds rates of return or cost escalation assumptions. Reply briefs were submitted on October 31, 2016. Intervenor parties reiterated that the Utility has not justified increases in costs due to large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility confirmed that the testimony and work papers support the cost increases as well as the total estimate to decommission Diablo Canyon.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.5 billion at December 31, 2016, which includes an $818 million adjustment to reflect the increased cost estimates and a $115 million increase resulting from the joint proposal described above, and $2.5 billion at December 31, 2015. These estimates are based on decommissioning cost studies, prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

As of December 31, 2016, the nuclear decommissioning trust accounts' total fair value was $2.9 billion. Changes in the estimated costs, the timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission.

CPUC Investigation of 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 CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment. The consultant's work began in the second quarter of 2016.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned commissioner will determine the scope of any next actions in the proceeding. The timing, scope and potential outcome of the investigation are uncertain.

2014 – 2015 Energy Efficiency Incentive Awards

On December 15, 2016, the CPUC approved a final 2014 - 2015 Energy Efficiency Incentive Award of $16.3 million, compared to the Utility's request of $19.1 million. The award includes a $5.8 million reduction reflecting the approved settlement agreement related to the rehearing of the 2006 - 2008 customer energy efficiency shareholder incentives. The settlement agreement requires the Utility to reduce future energy efficiency shareholder incentives by $29.1 million, which will be applied in installments of $5.8 million per year for five years, provided that the Utility has sufficient energy efficiency incentive awards to offset that amount. Due to the application of the first offset of $5.8 million, the required future energy efficiency reduction currently corresponds to $23.3 million. If shareholder incentives are insufficient to offset this amount, the offset in the following year will be increased by the shortfall. At its discretion, the Utility may increase the amount of the offset to reduce the remaining offset obligation more quickly. If the amount has not been fully offset at the end of five years, the balance will be credited against future energy efficiency program spending.

LEGISLATIVE AND REGULATORY INITIATIVES

The California Legislature and the CPUC have adopted requirements, policies, and decisions to improve and refine gas and electric safety citation programs, implement new state law requirements applicable to natural gas storage facilities, accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, promote customer energy efficiency and demand response programs, and foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. CPUC proceedings related to some of these matters are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

Gas and Electric Safety Citation Program

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day.

On September 29, 2016, the CPUC issued a final decision adopting improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replace the previous safety citation programs and adopts non-substantive changes to these programs so that the programs can be similar in structure and process where appropriate.

Natural Gas Storage Facilities

On January 6, 2016, the California Governor ordered the DOGGR to issue emergency regulations to require gas storage facility operators throughout California, including the Utility, to comply with new safety and reliability measures, including minimum daily inspection of gas storage well heads (using gas leak detection technology such as infrared imaging), ongoing verification of the mechanical integrity of all gas storage wells, ongoing measurement of annular gas pressure or annular gas flow within wells, regular testing of all safety valves used in wells, establishing minimum and maximum pressure limits for each gas storage facility in the state, and establishing a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipes and equipment. On February 5, 2016, the DOGGR adopted the emergency regulations. The Utility implemented the regulations and submitted an Underground Storage Risk and Integrity Management Plan on August 5, 2016 that is pending DOGGR approval.

Additionally, in September 2016, the California Governor signed SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California, which are expected to be finalized in the second half of 2017. The PHMSA has also issued interim final rules effective January 18, 2017 regulating gas storage facilities at the federal level. The Utility may incur significant costs to comply with the new regulations related to (1) the development of a natural gas leak prevention and response program, (2) the development of a plan for corrosion monitoring and evaluation, (3) proactive replacement of equipment at risk of failure, and (4) a review of risk management plans to consider new risk factors. The Utility plans to file an advice letter with the CPUC in the first quarter of 2017 to request a memorandum account to track the future incremental costs associated with implementing the new regulations. Upon approval, a subsequent application would be submitted to the CPUC for recovery of the incremental costs being tracked. The Utility is unable to estimate the timing and outcome of such request.

New Renewable Energy Targets

In October 2015, the California Governor signed SB 350 into law, which became effective January 1, 2016. SB 350 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. SB 350 includes increasing interim renewable energy targets for the periods between 2020 and 2030 and continues to include compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will 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.

In December 2016, the CPUC issued the first of a series of decisions to implement the RPS-related provisions of SB 350. The decision addressed compliance periods and procurement quantity requirements. Subsequent rulings and decisions are expected in 2017 to address scope and implementation details.

Additionally, as stated above, the Utility's application and joint proposal to retire Diablo Canyon include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of DERs. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service.

On January 24, 2017, the CPUC convened a workshop aimed at informing the development of a CPUC framework to evaluate grid-modernization investments. The workshop was attended by the California IOUs, the DER industry, consumer advocates, the DOE, and the CPUC's Energy Division staff. The Energy Division staff is expected to develop a grid modernization investment framework in the first quarter of 2017. Additionally, on February 9, 2017, the CPUC issued a decision approving two out of three of the Utility's proposed field demonstration projects to test various distribution-related services that DERs might provide to the Utility. The Utility in unable to predict when a final CPUC decision approving, disapproving, or modifying the Utility's electric distribution resources plan will be issued.

Integrated Distributed Energy Resources – Regulatory Incentives Pilot Program

On April 4, 2016, the assigned CPUC commissioner and ALJ issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling assumed that the incentive would take the form of an additional payment to the Utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The ruling also stated that it did not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities.

On September 1, 2016, the assigned CPUC commissioner and ALJ issued an amended scoping memo and ruling that re-categorized all activities in the proceeding as rate-setting, consolidated remaining issues into one phase, and proposed a revised regulatory incentive pilot to test how an earnings opportunity affects DER sourcing. On December 22, 2016, the CPUC issued a final decision in the proceeding which authorizes a pilot to test a regulatory incentive mechanism through which the Utility will earn a 4% pre-tax incentive on annual payments for DERs, as well as test a regulatory process that will allow the Utility to competitively solicit DER services to defer distribution infrastructure. Each utility is required to conduct at least one pilot, but may conduct up to three additional pilots.

Electric Rate Reform and Net Energy Metering (NEM)

On July 3, 2015, the CPUC approved a final decision to authorize the California IOUs to gradually flatten their tiered residential electric rate structures to two tiers by January 2019. The decision approved higher minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates (known as "default time-of-use rates") unless customers elect otherwise. The Utility also may propose to impose a fixed charge on residential electric customers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates.

In January 2016, the CPUC adopted new NEM rules. The new rules became effective for new NEM customers in December 2016, when the Utility reached its NEM cap of 2,409 MW. New NEM customers will be required to pay an interconnection fee, will be charged for energy use on time-of-use rates, and will be required to pay non-bypassable charges to help fund some of the costs of low-income, energy efficiency, and other programs that other customers pay. Unlike the initial NEM tariff, there is no cap on the total capacity of distributed generation that can be installed under the new rules, and there is no size limitation on the projects, so long as projects over 1MW pay actual interconnection costs. On March 7, 2016, the Utility and certain other parties, including TURN and CUE, filed applications for rehearing. The Utility requested that the CPUC vacate its January 2016 decision that the Utility asserts contains legal and factual errors. Many parties argued that the CPUC failed to complete its duties under AB 327, which required the CPUC to evaluate the costs and benefits of NEM. On September 15, 2016, the CPUC voted to deny the applications for rehearing, concluding that good cause had not been established to grant a rehearing and that the NEM decision adopted a successor tariff as required. The CPUC indicated that it may revisit the NEM successor tariff in 2019.

Electric Vehicle (EV) Infrastructure Development

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain EV charging stations and the associated infrastructure. On December 15, 2016, the CPUC issued a final decision establishing a three-year EV program of $130 million (approximately $109 million in capital expenditures) to deploy up to 7,500 charging stations. Further deployment of light-duty EV infrastructure will be considered in a second phase of the proceeding.

Transportation Electrification (TE) Application

SB 350 orders the CPUC, in consultation with the CARB 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 large IOUs to file projects to accelerate TE in the state, including both one-year projects (of up to $20 million total) and two to five-year programs with a requested revenue requirement determined by the utility. On January 20, 2017, the Utility filed its TE application with the CPUC requesting a total of up to $253 million (approximately $211 million in capital expenditures) in program funding over five years (2018 - 2022) primarily related to make-ready infrastructure for TE in medium to heavy-duty sectors. Protests are due March 6, 2017 and a prehearing conference is scheduled for March 16, 2017. The Utility expects a decision to be issued within 12 to 18 months.

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 CO2 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 and "Environmental Regulation" in Item 1.)

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. At December 31, 2016, $299 million and $135 million was accrued in the Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Topock site and the Hinkley site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See "Environmental Remediation Contingencies" in Note 13 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. 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, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

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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. 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 through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. (See "2015 Gas Transmission and Storage Rate Case" above.)

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $7 million and $2 million at December 31, 2016 and 2015, respectively. During 2016, the Utility's approximate high, low, and average values-at-risk were $7 million, $1 million and $4 million, respectively. During 2015, the value-at-risk amounts were $2 million, $1 million and $2 million, 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, 2016 and 2015, 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 $13 million and $11 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, 2016	$ 69	$ (11)	$ 58	3	39
December 31, 2015	64	$ (11)	$ 53	4	39

(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.

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. 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, 2016, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $9.9 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $7.7 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.

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 records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. 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.

The Utility recorded charges of $283 million in 2016 for capital spending that was disallowed related to the Penalty Decision. The Utility incurred charges of $219 million in 2016 for capital expenditures that will be disallowed based on the final phase two decision in its 2015 GT&S rate case. Additionally, the Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Loss Contingencies

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

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.

At December 31, 2016 and 2015, the Utility's accruals for undiscounted gross environmental liabilities were $958 million and $969 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.9 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.

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 policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. Management has made significant estimates and assumptions about accruals related to the Butte fire. At December 31, 2016, the Utility's accrual for the Butte fire was $690 million. Actual results may differ materially from these estimates and assumptions. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

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. Management has made significant estimates and assumptions about insurance recoveries related to the Butte fire. (See "Enforcement and Litigation Matters" and "Legal and Regulatory Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

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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, 2016, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $4.7 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. If the inflation adjustment or discount rate increased 25 basis points, the result would be an immaterial impact to ARO.

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.

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 2017 is 7.2%, gradually decreasing to the ultimate trend rate of 4.5% in 2025 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 5.3% compares to a ten-year actual return of 7.3%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 696 Aa-grade non-callable bonds at December 31, 2016. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

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

(in millions)	Increase (Decrease) in Assumption		Increase in 2016 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2016
Discount rate	(0.50)	%	$ 109	$ 1,319
Rate of return on plan assets	(0.50)	%	68	-
Rate of increase in compensation	0.50	%	59	306

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 2016 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2016
Health care cost trend rate	0.50	%	$ 4	$ 58
Discount rate	(0.50)	%	4	134
Rate of return on plan assets	(0.50)	%	10	-

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 which 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 2016 Form 10-K. 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," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the U 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 timing and outcomes of the Butte fire litigation, and whether the Utility's insurance is sufficient to cover the Utility's liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;

the timing and outcomes of the 2017 GRC, TO rate case, cost of capital proceeding, and other ratemaking and regulatory proceedings;

the terms of probation and the monitorship imposed in the sentencing phase of the Utility's federal criminal trial on January 26, 2017, the timing and outcomes of the debarment proceeding and potential remedial and other measures that could be imposed on the Utility as a result of that proceeding, 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-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

the timing and outcomes of the CPUC's investigation of communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, or of a potential settlement, and of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;

whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the Utility's conviction in the federal criminal trial, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

whether the Utility can control its costs within the authorized levels of spending, and successfully implement 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;

the timing and outcome of the complaint filed by the CPUC and certain other parties with the FERC on February 2, 2017; the complaint requests that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the California ISO's Transmission Planning Process in order to allow for participation and input from interested parties. The planning process that may result from come out of the proceeding may impact the scope and timing of capital transmission projects that the Utility will execute in the future;

the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

the outcomes of the SED's investigations of potential violations identified through audits, investigations, or self-reports including in connection with the Utility's February 2017 self-report related to its customer service representatives' drug and alcohol testing program;

the outcome of future investigations or other enforcement proceedings that may be commenced 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, inspection and maintenance practices, customer billing and privacy, and physical and cyber security, environmental laws and regulations;

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 ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

the impact of maintenance costs of the Utility electric transmission facilities;

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 actions taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out the Utility's Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether the Utility obtains the approvals required to withdraw its NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the WBA assertion that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act; and whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;

whether the Utility is successful in ensuring physical security of its critical assets and whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility and its third party vendors and contractors (who host, maintain, modify and update some of the Utility's systems) are able to protect the Utility's operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;

the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), 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; 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;

how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, electric vehicles, 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 SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures, as well the impact of the PHMSA rules effective January 18, 2017 regulating gas storage facilities at the federal level;

whether the Utility's climate change adaptation strategies are successful;

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 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 on acceptable terms;

changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose their investment grade credit ratings;

the impact of federal or state laws or regulations, or their interpretation, on energy policy and 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 ultimate outcomes of the CPUC's pending investigations, the jury's verdict in the federal criminal trial of the Utility and its possible conviction, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

the impact of the corporate tax reform considered by the new federal administration and 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 new federal administration; and

the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item. 1A. Risk Factors above and our 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.

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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PG&E Corporation

CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share amounts)

	Year ended December 31,		
	2016	2015	2014
Operating Revenues			
Electric	$13,864	$13,657	$13,658
Natural gas	3,802	3,176	3,432
Total operating revenues	17,666	16,833	17,090
Operating Expenses			
Cost of electricity	4,765	5,099	5,615
Cost of natural gas	615	663	954
Operating and maintenance	7,354	6,951	5,638
Depreciation, amortization, and decommissioning	2,755	2,612	2,433
Total operating expenses	15,489	15,325	14,640
Operating Income	2,177	1,508	2,450
Interest income	23	9	9
Interest expense	(829)	(773)	(734)
Other income, net	91	117	70
Income Before Income Taxes	1,462	861	1,795
Income tax provision (benefit)	55	(27)	345
Net Income	1,407	888	1,450
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	$1,393	$874	$1,436
Weighted Average Common Shares Outstanding, Basic	499	484	468
Weighted Average Common Shares Outstanding, Diluted	501	487	470
Net Earnings Per Common Share, Basic	$2.79	$1.81	$3.07
Net Earnings Per Common Share, Diluted	$2.78	$1.79	$3.06

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year ended December 31,		
	2016	2015	2014
Net Income	$1,407	$888	$1,450
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations			
(net of taxes of $1, $0, and $10, at respective dates)	(2)	(1)	(14)
Net change in investments			
(net of taxes of $0, $12, and $17 at respective dates)	-	(17)	(25)
Total other comprehensive income (loss)	(2)	(18)	(39)
Comprehensive Income	1,405	870	1,411
Preferred stock dividend requirement of subsidiary	14	14	14
Comprehensive Income Attributable to Common Shareholders	$1,391	$856	$1,397

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at December 31,	
	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	$177	$123
Restricted cash	7	234
Accounts receivable		
Customers (net of allowance for doubtful accounts of $58 and $54 at respective dates)	1,252	1,106
Accrued unbilled revenue	1,098	855
Regulatory balancing accounts	1,500	1,760
Other	801	286
Regulatory assets	423	517
Inventories		
Gas stored underground and fuel oil	117	126
Materials and supplies	346	313
Income taxes receivable	160	155
Other	283	338
Total current assets	6,164	5,813
Property, Plant, and Equipment		
Electric	52,556	48,532
Gas	17,853	16,749
Construction work in progress	2,184	2,059
Other	2	2
Total property, plant, and equipment	72,595	67,342
Accumulated depreciation	(22,014)	(20,619)
Net property, plant, and equipment	50,581	46,723
Other Noncurrent Assets		
Regulatory assets	7,951	7,029
Nuclear decommissioning trusts	2,606	2,470
Income taxes receivable	70	135
Other	1,226	1,064
Total other noncurrent assets	11,853	10,698
TOTAL ASSETS	$68,598	$63,234

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31, 2016	2015
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$1,516	$1,019
Long-term debt, classified as current	700	160
Accounts payable		
Trade creditors	1,495	1,414
Regulatory balancing accounts	645	715
Other	433	398
Disputed claims and customer refunds	236	454
Interest payable	216	206
Other	2,323	1,997
Total current liabilities	7,564	6,363
Noncurrent Liabilities		
Long-term debt	16,220	15,925
Regulatory liabilities	6,805	6,321
Pension and other postretirement benefits	2,641	2,622
Asset retirement obligations	4,684	3,643
Deferred income taxes	10,213	9,206
Other	2,279	2,326
Total noncurrent liabilities	42,842	40,043
Commitments and Contingencies (Note 13)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 506,891,874 and 492,025,443 shares outstanding at respective dates	12,198	11,282
Reinvested earnings	5,751	5,301
Accumulated other comprehensive loss	(9)	(7)
Total shareholders' equity	17,940	16,576
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	18,192	16,828
TOTAL LIABILITIES AND EQUITY	$68,598	$63,234

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2016	2015	2014
Cash Flows from Operating Activities			
Net income	$ 1,407	$ 888	$ 1,450
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,755	2,612	2,433
Allowance for equity funds used during construction	(112)	(107)	(100)
Deferred income taxes and tax credits, net	1,030	693	690
Disallowed capital expenditures	507	407	116
Other	379	326	286
Effect of changes in operating assets and liabilities:			
Accounts receivable	(473)	(177)	13
Butte-related insurance receivable	(575)	-	-
Inventories	(24)	37	(22)
Accounts payable	180	(55)	(61)
Butte-related third-party claims	690	-	-
Income taxes receivable/payable	(5)	43	376
Other current assets and liabilities	83	(288)	218
Regulatory assets, liabilities, and balancing accounts, net	(1,214)	(244)	(1,642)
Other noncurrent assets and liabilities	(219)	(355)	(67)
Net cash provided by operating activities	4,409	3,780	3,690
Cash Flows from Investing Activities			
Capital expenditures	(5,709)	(5,173)	(4,833)
Decrease in restricted cash	227	64	3
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,295	1,268	1,336
Purchases of nuclear decommissioning trust investments	(1,352)	(1,392)	(1,334)
Other	13	22	114
Net cash used in investing activities	(5,526)	(5,211)	(4,714)
Cash Flows from Financing Activities			
Borrowings (repayments) under revolving credit facilities	-	-	(260)
Net issuances (repayments) of commercial paper, net of discount of $6, $3, and $2 at respective dates	(9)	683	(583)
Short-term debt financing	500	-	300
Short-term debt matured	-	(300)	-
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $17, $27 and $17 at respective dates	983	1,123	2,308
Repayments of long-term debt	(160)	-	(889)
Common stock issued	822	780	802
Common stock dividends paid	(921)	(856)	(828)

Other	(44)	(27)	29
Net cash provided by financing activities	1,171	1,403	879
Net change in cash and cash equivalents	54	(28)	(145)
Cash and cash equivalents at January 1	123	151	296
Cash and cash equivalents at December 31	$ 177	$ 123	$ 151

Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$(726)	$(684)	$(633)
Income taxes, net	231	77	501
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$248	$224	$217
Capital expenditures financed through accounts payable	403	440	339
Noncash common stock issuances	20	21	21
Terminated capital leases	18	-	71

See accompanying Notes to the Consolidated Financial Statements.

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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, 2013	456,670,424	$9,550	$ 4,742	$ 50	$ 14,342	$ 252	$14,594
Net income	-	-	1,450	-	1,450	-	1,450
Other comprehensive income	-	-	-	(39)	(39)	-	(39)
Common stock issued, net	19,242,980	823	-	-	823	-	823
Stock-based compensation amortization	-	65	-	-	65	-	65
Common stock dividends declared	-	-	(862)	-	(862)	-	(862)
Tax expense from employee stock plans	-	(17)	-	-	(17)	-	(17)
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2014	475,913,404	$10,421	$ 5,316	$ 11	$ 15,748	$ 252	$16,000
Net income	-	-	888	-	888	-	888
Other comprehensive loss	-	-	-	(18)	(18)	-	(18)
Common stock issued, net	16,112,039	801	-	-	801	-	801
Stock-based compensation amortization	-	66	-	-	66	-	66
Common stock dividends declared	-	-	(889)	-	(889)	-	(889)
Tax expense from employee stock plans	-	(6)	-	-	(6)	-	(6)
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
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 loss	-	-	-	(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

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF INCOME

(in millions)

	Year ended December 31,		
	2016	2015	2014
Operating Revenues			
Electric	$13,865	$13,657	$13,656
Natural gas	3,802	3,176	3,432
Total operating revenues	17,667	16,833	17,088
Operating Expenses			
Cost of electricity	4,765	5,099	5,615
Cost of natural gas	615	663	954
Operating and maintenance	7,352	6,949	5,635
Depreciation, amortization, and decommissioning	2,754	2,611	2,432
Total operating expenses	15,486	15,322	14,636
Operating Income	2,181	1,511	2,452
Interest income	22	8	8
Interest expense	(819)	(763)	(720)
Other income, net	88	87	77
Income Before Income Taxes	1,472	843	1,817
Income tax provision (benefit)	70	(19)	384
Net Income	1,402	862	1,433
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	$1,388	$848	$1,419

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year ended December 31,		
	2016	2015	2014
Net Income	$1,402	$862	$1,433
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations			
(net of taxes of $1, $1, and $6, at respective dates)	(1)	(2)	(8)
Total other comprehensive income (loss)	(1)	(2)	(8)
Comprehensive Income	$1,401	$860	$1,425

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at December 31, 2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	$71	$59
Restricted cash	7	234
Accounts receivable		
Customers (net of allowance for doubtful accounts of $58 and $54 at respective dates)	1,252	1,106
Accrued unbilled revenue	1,098	855
Regulatory balancing accounts	1,500	1,760
Other	801	284
Regulatory assets	423	517
Inventories		
Gas stored underground and fuel oil	117	126
Materials and supplies	346	313
Income taxes receivable	159	130
Other	282	338
Total current assets	6,056	5,722
Property, Plant, and Equipment		
Electric	52,556	48,532
Gas	17,853	16,749
Construction work in progress	2,184	2,059
Total property, plant, and equipment	72,593	67,340
Accumulated depreciation	(22,012)	(20,617)
Net property, plant, and equipment	50,581	46,723
Other Noncurrent Assets		
Regulatory assets	7,951	7,029
Nuclear decommissioning trusts	2,606	2,470
Income taxes receivable	70	135
Other	1,110	958
Total other noncurrent assets	11,737	10,592
TOTAL ASSETS	$68,374	$63,037

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,	
	2016	2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$1,516	$1,019
Long-term debt, classified as current	700	160
Accounts payable		
Trade creditors	1,494	1,414
Regulatory balancing accounts	645	715
Other	453	418
Disputed claims and customer refunds	236	454
Interest payable	214	203
Other	2,072	1,750
Total current liabilities	7,330	6,133
Noncurrent Liabilities		
Long-term debt	15,872	15,577
Regulatory liabilities	6,805	6,321
Pension and other postretirement benefits	2,548	2,534
Asset retirement obligations	4,684	3,643
Deferred income taxes	10,510	9,487
Other	2,230	2,282
Total noncurrent liabilities	42,649	39,844
Commitments and Contingencies (Note 13)		
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	8,050	7,215
Reinvested earnings	8,763	8,262
Accumulated other comprehensive income	2	3
Total shareholders' equity	18,395	17,060
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$68,374	$63,037

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2016	2015	2014
Cash Flows from Operating Activities			
Net income	$1,402	$862	$1,433
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,754	2,611	2,432
Allowance for equity funds used during construction	(112)	(107)	(100)
Deferred income taxes and tax credits, net	1,042	714	731
Disallowed capital expenditures	507	407	116
Other	306	263	226
Effect of changes in operating assets and liabilities:			
Accounts receivable	(475)	(177)	16
Butte-related insurance receivable	(575)	-	-
Inventories	(24)	37	(22)
Accounts payable	179	(2)	(55)
Butte-related third-party claims	690	-	-
Income taxes receivable/payable	(29)	38	395
Other current assets and liabilities	112	(315)	168
Regulatory assets, liabilities, and balancing accounts, net	(1,214)	(244)	(1,642)
Other noncurrent assets and liabilities	(219)	(340)	(66)
Net cash provided by operating activities	4,344	3,747	3,632
Cash Flows from Investing Activities			
Capital expenditures	(5,709)	(5,173)	(4,833)
Decrease in restricted cash	227	64	3
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,295	1,268	1,336
Purchases of nuclear decommissioning trust investments	(1,352)	(1,392)	(1,334)
Other	13	22	29
Net cash used in investing activities	(5,526)	(5,211)	(4,799)
Cash Flows from Financing Activities			
Net issuances (repayments) of commercial paper, net of discount of $6, $3, and $2 at respective dates	(9)	683	(583)
Short-term debt financing	500	-	300
Short-term debt matured	-	(300)	-
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $17, $27, and $14 at respective dates	983	1,123	1,961
Repayments of long-term debt	(160)	-	(539)
Preferred stock dividends paid	(14)	(14)	(14)

Common stock dividends paid	(911)	(716)	(716)
Equity contribution from PG&E Corporation	835	705	705
Other	(30)	(13)	43
Net cash provided by financing activities	1,194	1,468	1,157
Net change in cash and cash equivalents	12	4	(10)
Cash and cash equivalents at January 1	59	55	65
Cash and cash equivalents at December 31	$71	$59	$55

Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$(717)	$(675)	$(618)
Income taxes, net	244	77	500
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$403	$440	$339
Terminated capital leases	18	-	71

See accompanying Notes to the Consolidated Financial Statements.

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, 2013	$ 258	$ 1,322	$ 5,821	$ 7,427	$ 13	$ 14,841
Net income	-	-	-	1,433	-	1,433
Other comprehensive income	-	-	-	-	(8)	(8)
Equity contribution	-	-	705	-	-	705
Tax expense from employee stock plans	-	-	(12)	-	-	(12)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2014	$ 258	$ 1,322	$ 6,514	$ 8,130	$ 5	$ 16,229
Net income	-	-	-	862	-	862
Other comprehensive loss	-	-	-	-	(2)	(2)
Equity contribution	-	-	705	-	-	705
Tax expense from employee stock plans	-	-	(4)	-	-	(4)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
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 loss	-	-	-	-	(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

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

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

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

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

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation and Regulated Operations

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

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

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

Revenue Recognition

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

Cash and Cash Equivalents

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

Restricted Cash

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

Allowance for Doubtful Accounts Receivable

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

Inventories

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

Emission Allowances

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

Property, Plant, and Equipment

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

	Estimated Useful	Balance at December 31,	
(in millions, except estimated useful lives)	Lives (years)	2016	2015
Electricity generating facilities (1)	5 to 100	$11,308	$9,860
Electricity distribution facilities	15 to 55	29,836	28,476
Electricity transmission facilities	15 to 75	11,412	10,196
Natural gas distribution facilities	5 to 60	11,362	10,397
Natural gas transmission and storage facilities	5 to 65	6,491	6,352
Construction work in progress		2,184	2,059
Total property, plant, and equipment		72,593	67,340
Accumulated depreciation		(22,012)	(20,617)
Net property, plant, and equipment		$50,581	$46,723

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 13 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.73% in 2016, 3.80% in 2015, and 3.77% in 2014. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $51 million and $112 million during 2016, $48 million and $107 million during 2015, and $45 million and $100 million during 2014.

Asset Retirement Obligations

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

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

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

Nuclear Decommissioning Obligation

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

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

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

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. (See “Enforcement and Litigation Matters” in Note 13 below.)

Nuclear Decommissioning Trusts

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

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

Variable Interest Entities

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

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2016, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2016, it did not consolidate any of them.

Other Accounting Policies

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Note 13 herein.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2016 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
Beginning balance	$ (23)	$ 16	$(7)
Other comprehensive income before reclassifications:			
Unrecognized prior service cost			
(net of taxes of $37 and $15, respectively)	54	(21)	33
Unrecognized net actuarial loss			
(net of taxes of $45 and $15, respectively)	(64)	21	(43)
Regulatory account transfer			
(net of taxes of $5 and $0, respectively)	7	-	7
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost			
(net of taxes of $3 and $6, respectively) (1)	5	9	14
Amortization of net actuarial loss			
(net of taxes of $10 and $2, respectively) (1)	14	2	16
Regulatory account transfer			

(net of taxes of $13 and $8, respectively) (1)	(18)	(11)	(29)
Net current period other comprehensive loss	(2)	-	(2)
Ending balance	$ (25)	$ 16	$(9)

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

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

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
Beginning balance	$ (21)	$ 15	$ 17	$ 11
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss				
(net of taxes of $51, $21, and $0, respectively)	(76)	(31)	-	(107)
Regulatory account transfer				
(net of taxes of $51, $21, and $0, respectively)	73	31	-	104
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $7, $8, and $0, respectively) (1)	8	11	-	19
Amortization of net actuarial loss				
(net of taxes of $4, $1, and $0, respectively) (1)	6	3	-	9
Regulatory account transfer				
(net of taxes of $10, $9, and $0, respectively) (1)	(13)	(13)	-	(26)
Realized gain on investments				
(net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive loss	(2)	1	(17)	(18)
Ending balance	$ (23)	$ 16	$ -	$ (7)

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

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

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Recently Adopted Accounting Guidance

Share-Based Payment Accounting

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

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

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

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

Fair Value Measurement

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

Accounting for Fees Paid in a Cloud Computing Arrangement

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

Presentation of Debt Issuance Costs

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

Accounting Standards Issued But Not Yet Adopted

Restricted Cash

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

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing guidance relating to the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheet, which were previously not recognized. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, which amends the existing guidance relating to the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Revenue Recognition Standard

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

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NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

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

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP.

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

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

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	2016	2015
Cost of removal obligations (1)	$5,060	$4,605
Recoveries in excess of AROs (2)	626	631
Public purpose programs (3)	567	600
Other	552	485
Total long-term regulatory liabilities	$6,805	$6,321

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

(2) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 10 below.)

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

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Regulatory Balancing Accounts

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

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

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

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

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

NOTE 4: DEBT

Long-Term Debt

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

		December 31,	
(in millions)		2016	2015
PG&E Corporation			
Senior notes:			
Maturity	Interest Rates		
2019	2.40%	350	350
Unamortized discount, net of premium and debt issuance costs		(2)	(2)
Total PG&E Corporation long-term debt		348	348
Utility			
Senior notes:			
Maturity	Interest Rates		
2017	5.625%	700	700
2018	8.25%	800	800
2020	3.50%	800	800
2021	3.25% to 4.25%	550	550
2022 through 2046	2.45% to 6.35%	12,775	11,775
Less: current portion		(700)	-
Unamortized discount, net of premium and debt issuance costs		(161)	(156)
Total senior notes, net of current portion		14,764	14,469
Pollution control bonds:			
Maturity	Interest Rates		
Series 2004 A-D, due 2023(1)	4.75%	345	345
Series 2009 A-D, due 2026 (2)	variable rate(4)	149	309
Series 1996 C, E, F, 1997 B due 2026(3)	variable rate(5)	614	614
Less: current portion		-	(160)
Total pollution control bonds		1,108	1,108
Total Utility long-term debt, net of current portion		15,872	15,577
Total consolidated long-term debt, net of current portion		$ 16,220	$ 15,925

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

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

(3) Each series of these bonds is supported by a separate letter of credit. In December 2015, the letters of credit were extended to December 1, 2020. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

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

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

Pollution Control Bonds

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

Repayment Schedule

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2016 are reflected in the table below:

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

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

Short-term Borrowings

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

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

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

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

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

Revolving Credit Facilities

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

Borrowings under each credit agreement (other than swingline loans) will bear interest based, at each borrower’s election, on (1) a London Interbank Offered Rate (“LIBOR”) plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent’s announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation’s credit agreement and between 0.8% and 1.275% under the Utility’s credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation’s credit agreement and between 0% and 0.275% under the Utility’s credit agreement. In addition, the facility fee under PG&E Corporation’s and the Utility’s credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

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

Commercial Paper Programs

The borrowings from PG&E Corporation’s and the Utility’s commercial paper programs are used primarily to fund temporary financing needs. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation’s and the Utility’s other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2016, the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.63% and 0.64%, respectively.

Other Short-term Borrowings

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

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

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

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

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

In addition, during 2016, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $364 million.

Dividends

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. In May 2016, the Board of Directors of PG&E Corporation adopted a new quarterly common stock dividend of $0.49 per share. In 2016, total dividends were $1.925 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Additionally, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over five years. At December 31, 2016, the Utility had restricted net assets of $15.8 billion and was limited to $25 million of additional common stock dividends it could pay to PG&E Corporation.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 13,826,995 shares were available for future awards at December 31, 2016.

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

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

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

Restricted Stock Units

Prior to 2014, restricted stock units generally vested over four years in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2016, 2015, and 2014 was $56.68, $53.30, and $43.76, respectively. The total fair value of restricted stock units that vested during 2016, 2015, and 2014 was $36 million, $57 million, and $34 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2016, $37 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.22 years.

The following table summarizes restricted stock unit activity for 2016:

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

Performance Shares

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

Compensation expense attributable to performance share is generally recognized rateably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2016, 2015, and 2014 was $53.61, $68.27, and $51.81 respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2016, $40 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.57 years.

The following table summarizes activity for performance shares in 2016:

	Number of Performance Shares	Weighted Average Grant-

		Date Fair Value
Nonvested at January 1	1,450,612	$ 59.24
Granted	1,233,884	53.61
Vested	(777,719)	51.81
Forfeited (1)	(67,922)	58.20
Nonvested at December 31	1,838,855	$ 58.65

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

NOTE 6: PREFERRED STOCK

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

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2016 and December 31, 2015, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

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At December 31, 2016, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2016, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

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

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2016, 2015, and 2014.

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

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

NOTE 8: INCOME TAXES

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

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

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

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

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

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	2016	2015	2014	2016	2015	2014
Current:						
Federal	$(105)	$(89)	$(84)	$(105)	$(88)	$(84)
State	(70)	11	(41)	(66)	6	(29)
Deferred:						
Federal	218	131	396	229	136	426
State	16	(76)	78	16	(69)	75
Tax credits	(4)	(4)	(4)	(4)	(4)	(4)
Income tax provision (benefit)	$55	$(27)	$345	$70	$(19)	$384

The following table describes net deferred income tax liabilities:

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

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

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

(3) Amounts primarily relate to regulatory balancing accounts. Greenhouse gas allowances are temporary timing differences that reverse through regulatory balancing accounts.

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

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2016	2015	2014	2016	2015	2014
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	(2.5)	(4.9)	1.4	(2.2)	(4.8)	1.6
Effect of regulatory treatment of fixed asset differences (2)	(23.7)	(33.6)	(15.0)	(23.4)	(33.7)	(14.7)
Tax credits	(0.8)	(1.3)	(0.7)	(0.8)	(1.3)	(0.7)
Benefit of loss carryback	(1.1)	(1.5)	(0.8)	(1.1)	(1.5)	(0.8)
Non deductible penalties (3)	0.8	4.3	0.3	0.8	4.3	0.3
Other, net (4)	(3.9)	(1.1)	(0.8)	(3.5)	(0.2)	0.4
Effective tax rate	3.8 %	(3.1) %	19.4 %	4.8 %	(2.2) %	21.1 %

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

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacts only 2016. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.

(3) Primarily represents the effects of non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for the year ended December 31, 2016 and the effects of the Penalty Decision for the year ended December 31, 2015. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

(4) In 2016, the amount primarily represents the impact of tax audit settlements.

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

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

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2016 for PG&E Corporation and the Utility was $25 million.

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PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $70 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2016, 2015, and 2014, these amounts were immaterial.

IRS settlements

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

PG&E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relates to deductible repair costs. In March 2016, PG&E Corporation reached an agreement with the IRS on deductible electric transmission and distribution repair costs for the 2012 tax year. The agreement provided that the methodology used in determining the deductible amount should be followed for all subsequent periods, absent any material change in facts. Deductible repair costs for other lines of business will continue to be subject to examination by the IRS for subsequent years. The IRS is expected to issue guidance in 2017 that clarifies which repair costs are deductible for the natural gas transmission and distribution businesses.

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

2015 Gas Transmission and Storage Rate Case

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

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

Carryforwards

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

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

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2016 for these tax attributes.

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NOTE 9: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.

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

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

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

Volume of Derivative Activity

At December 31, 2016 and 2015, respectively, the volumes of the Utility's outstanding derivatives were as follows:

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

(1) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

(2) Million British Thermal Units.

(3) CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At December 31, 2016, the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$91	$ (10)	$ 1	$ 82
Other noncurrent assets – other	149	(9)	-	140
Current liabilities – other	(48)	10	-	(38)
Noncurrent liabilities – other	(101)	9	3	(89)
Total commodity risk	$91	$ -	$ 4	$ 95

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At December 31, 2015, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
	Gross Derivative			Total Derivative
(in millions)	Balance	Netting	Cash Collateral	Balance
Current assets – other	$97	$ (4)	$ 25	$ 118
Other noncurrent assets – other	172	(2)	-	170
Current liabilities – other	(102)	4	44	(54)
Noncurrent liabilities – other	(140)	2	21	(117)
Total commodity risk	$27	$ -	$ 90	$ 117

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

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

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

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

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2016, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

(in millions)	Balance at December 31, 2016	2015
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (24)	$ (2)
Related derivatives in an asset position	19	-
Collateral posting in the normal course of business related to these derivatives	4	-
Net position of derivative contracts/additional collateral posting requirements (1)	$ (1)	$ (2)

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility’s credit risk-related contingencies.

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NOTE 10: FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

	Fair Value Measurements At December 31, 2016				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$105	$-	$-	$ -	$105
Nuclear decommissioning trusts					
Short-term investments	9	-	-	-	9
Global equity securities	1,724	-	-	-	1,724
Fixed-income securities	665	527	-	-	1,192
Assets measured at NAV	-	-	-	-	14
Total nuclear decommissioning trusts (2)	2,398	527	-	-	2,939
Price risk management instruments (Note 9)					
Electricity	30	18	181	(18)	211
Gas	-	11	-	-	11
Total price risk management instruments	30	29	181	(18)	222
Rabbi trusts					
Fixed-income securities	-	61	-	-	61
Life insurance contracts	-	70	-	-	70
Total rabbi trusts	-	131	-	-	131
Long-term disability trust					
Short-term investments	8	-	-	-	8
Assets measured at NAV	-	-	-	-	170
Total long-term disability trust	8	-	-	-	178
TOTAL ASSETS	$2,541	$687	$181	$ (18)	$3,575
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$9	$12	$126	$ (21)	$126
Gas	-	2	-	(1)	1
TOTAL LIABILITIES	$9	$14	$126	$ (22)	$127

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $333 million, primarily related to deferred taxes on appreciation of investment value.

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(in millions)	Fair Value Measurements At December 31, 2015 Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$64	$-	$-	$ -	$64
Nuclear decommissioning trusts					
Short-term investments	36	-	-	-	36
Global equity securities	1,520	-	-	-	1,520
Fixed-income securities	694	521	-	-	1,215
Assets measured at NAV	-	-	-	-	13
Total nuclear decommissioning trusts (2)	2,250	521	-	-	2,784
Price risk management instruments (Note 9)					
Electricity	-	9	259	18	286
Gas	-	1	-	1	2
Total price risk management instruments	-	10	259	19	288
Rabbi trusts					
Fixed-income securities	-	57	-	-	57
Life insurance contracts	-	70	-	-	70
Total rabbi trusts	-	127	-	-	127
Long-term disability trust					
Short-term investments	7	-	-	-	7
Assets measured at NAV	-	-	-	-	158
Total long-term disability trust	7	-	-	-	165
TOTAL ASSETS	$2,321	$658	$259	$ 19	$3,428
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$69	$1	$170	$ (70)	$170
Gas	-	2	-	(1)	1
TOTAL LIABILITIES	$69	$3	$170	$ (71)	$171

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $314 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the years ended December 31, 2016 and 2015.

Trust Assets

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

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

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent) and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Price Risk Management Instruments

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

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

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

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

Level 3 Measurements and Sensitivity Analysis

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

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

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(in millions)	Fair Value at At December 31, 2016		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$181	$ 35	Market approach	CRR auction prices	$(11.88) - 6.93
Power purchase agreements	$-	$ 91	Discounted cash flow	Forward prices	$18.07 - 38.80

(1) Represents price per megawatt-hour

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

(1) Represents price per megawatt-hour

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2016 and 2015, respectively:

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

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

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2016 and 2015, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2016 and 2015.

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

	At December 31,			
	2016		2015	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation	$348	$352	$348	$354
Utility	15,813	17,790	14,818	16,422

Available for Sale Investments

The following table provides a summary of available-for-sale investments:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of December 31, 2016				
Nuclear decommissioning trusts				
Short-term investments	$ 9	$-	$-	$9
Global equity securities	584	1,157	(3)	1,738
Fixed-income securities	1,156	48	(12)	1,192
Total (1)	$ 1,749	$1,205	$(15)	$2,939
As of December 31, 2015				
Nuclear decommissioning trusts				
Short-term investments	$ 36	$-	$-	$36
Global equity securities	508	1,034	(9)	1,533
Fixed-income securities	1,165	58	(8)	1,215
Total (1)	$ 1,709	$1,092	$(17)	$2,784

(1) Represents amounts before deducting $333 million and $314 million at December 31, 2016 and 2015, respectively, primarily related to deferred taxes on appreciation of investment value.

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

(in millions)	As of December 31, 2016
Less than 1 year	$ 13
1–5 years	419
5–10 years	255
More than 10 years	505
Total maturities of fixed-income securities	$ 1,192

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

	2016	2015	2014

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

NOTE 11: EMPLOYEE BENEFIT PLANS

Pension Plan and Postretirement Benefits Other than Pensions (“PBOP”)

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate (“Pension Plan”). The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation’s and the Utility’s funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility’s minimum funding requirements related to its pension plans is zero.

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

Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2016 and 2015:

Pension Plan

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

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

Postretirement Benefits Other than Pensions

(in millions)	2016	2015
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 2,035	$ 2,092
Actual return on plan assets	167	(26)
Company contributions	52	61
Plan participant contribution	85	68
Benefits and expenses paid	(166)	(160)
Fair value of plan assets at end of year	$ 2,173	$ 2,035
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 1,766	$ 1,811
Service cost for benefits earned	52	55
Interest cost	76	71
Actuarial (gain) loss	11	(98)
Plan amendments	37	-
Transitional costs	-	1
Benefits and expenses paid	(153)	(146)
Federal subsidy on benefits paid	3	4
Plan participant contributions	85	68
Benefit obligation at end of year	$ 1,877	$ 1,766
Funded Status: (1)		
Noncurrent asset	$ 368	$ 344
Noncurrent liability	(72)	(75)
Net asset at end of year	$ 296	$ 269

(1) At December 31, 2016 and 2015, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

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

Components of Net Periodic Benefit Cost

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

Pension Plan

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

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

Postretirement Benefits Other than Pensions

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

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

Components of Accumulated Other Comprehensive Income

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

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2017 are as follows:

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

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

	Pension Plan December 31,			PBOP Plans December 31,		
	2016	2015	2014	2016	2015	2014
Discount rate	4.11 %	4.37 %	4.00 %	4.05 - 4.19 %	4.27 - 4.48 %	3.89 - 4.09 %
Rate of future compensation increases	4.00 %	4.00 %	4.00 %	-	-	-
Expected return on plan assets	5.30 %	6.10 %	6.20 %	2.80 - 6.00 %	3.20 - 6.60 %	3.30 - 6.70 %

The assumed health care cost trend rate as of December 31, 2016 was 7.2%, decreasing gradually to an ultimate trend rate in 2025 and beyond of approximately 4.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on postretirement benefit obligation	$ 118	$ (120)
Effect on service and interest cost	9	(10)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 5.3% compares to a ten-year actual return of 7.3%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 696 Aa-grade non-callable bonds at December 31, 2016. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

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

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

In the Pension Plan, target allocations for 2017 were updated to reflect a 2% increase in global equity investments and a 2% decrease in fixed income investments. Target allocations for PBOP Plans remain unchanged. Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

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

	Pension Plan			PBOP Plans		
	2017	2016	2015	2017	2016	2015
Global equity	27 %	25 %	25 %	32 %	32 %	31 %
Absolute return	5 %	5 %	5 %	3 %	3 %	3 %
Real assets	10 %	10 %	10 %	7 %	7 %	8 %
Fixed income	58 %	60 %	60 %	58 %	58 %	58 %
Total	100 %	100 %	100 %	100 %	100 %	100 %

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

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2016 and 2015.

	Fair Value Measurements At December 31,							
	2016				2015			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Plan:								
Short-term investments	$364	$369	$ -	$733	$247	$375	$ -	$622

Global equity	996	-	-	996	903	-	-	903
Real assets	610	-	-	610	581	-	-	581
Fixed-income	1,754	4,774	5	6,533	1,841	4,495	3	6,339
Assets measured at NAV	-	-	-	5,950	-	-	-	5,308
Total	$3,724	$5,143	$ 5	$14,822	$3,572	$4,870	$ 3	$13,753
PBOP Plans:								
Short-term investments	$33	$-	$ -	$33	$20	$-	$ -	$20
Global equity	115	-	-	115	104	-	-	104
Real assets	70	-	-	70	69	-	-	69
Fixed-income	150	656	-	806	150	632	-	782
Assets measured at NAV	-	-	-	1,153	-	-	-	1,065
Total	$368	$656	$ -	$2,177	$343	$632	$ -	$2,040
Total plan assets at fair value				$16,999				$15,793

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

Valuation Techniques

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

Short-Term Investments

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

Global Equity

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

Real Assets

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

Fixed-Income

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

Assets Measured at NAV

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent) and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the pension and PBOP plans that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges, hedge funds, private real estate funds, and fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Transfers Between Levels

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2016 and 2015.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2016 and 2015:

(in millions) For the year ended December 31, 2016	Fixed-Income
Balance at beginning of year	$ 3
Actual return on plan assets:	
Relating to assets still held at the reporting date	3
Relating to assets sold during the period	-
Purchases, issuances, sales, and settlements:	
Purchases	-
Settlements	(1)
Balance at end of year	$ 5

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

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

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $52 million to the other benefit plans in 2016. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2016. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $61 million to the pension plan and other postretirement benefit plans, respectively, for 2017.

Benefits Payments and Receipts

As of December 31, 2016, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	Pension Plan	PBOP Plans	Federal Subsidy
2017	$739	$87	$ (8)
2018	781	93	(9)
2019	821	97	(10)
2020	857	103	(10)
2021	892	108	(11)
Thereafter in the succeeding five years	4,879	592	(15)

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

Retirement Savings Plan

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation’s Consolidated Statements of Income were $97 million, $89 million, and $80 million in 2016, 2015, and 2014, respectively.

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

NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS

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

The Utility's significant related party transactions were:

	Year Ended December 31,		
(in millions)	2016	2015	2014
Utility revenues from:			
Administrative services provided to PG&E Corporation	$7	$6	$5
Utility expenses from:			
Administrative services received from PG&E Corporation	$74	$53	$54
Utility employee benefit due to PG&E Corporation	91	82	70

At December 31, 2016 and 2015, the Utility had receivables of $18 million and $22 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $22 million and $21 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 13: CONTINGENCIES AND COMMITMENTS

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

Enforcement and Litigation Matters

CPUC Matters

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

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

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

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

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

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

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

CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping

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

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

On September 26, 2016, the SED filed an application for rehearing of the CPUC's decision. Specifically, the application indicates that the CPUC erred in certain of its determinations (including those related to maximum allowable operating pressure documentation that, if adopted, could result in an additional fine of $7 million), calculations (including those related to the missing De Anza records violations) and certain other findings, and requests that the CPUC adopt its recommendations. On October 11, 2016, the Utility submitted its response to the

CPUC in which it opposed the SED's application for rehearing arguing that the application failed to identify a legal error warranting rehearing by the CPUC. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the SED's recommendations.

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

Natural Gas Transmission Pipeline Rights-of-Way

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

Potential Safety Citations

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on a less than daily basis, for violations that continued for more than one day. The SED can consider the discretionary factors discussed above (see "Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. There is also an administrative limit of $8 million per citation issued.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose penalties or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations, based on the SED's investigations of incidents reported to the CPUC, or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits or investigations. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED and other CPUC staff has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

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

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

Federal Matters

Federal Criminal Trial

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

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

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

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

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

Other Federal Matters

In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The investigation involves a removal by the Utility of a hazardous tree that contained an osprey nest and egg in Inverness, California, on March 18, 2016. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

Other Matters

Butte Fire Litigation

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

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

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

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

Loss Accrual (in millions)	
Balance at December 31, 2015	$ -
Accrued losses	750
Payments	(60)
Balance at December 31, 2016	$ 690

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

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of $750 million accrued through December 31, 2016 but is currently unable to reasonably estimate the upper end of the range of losses because it is still in an early stage of the evaluation of claims, the mediation and settlement process, and discovery. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. The Utility has recorded $625 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility is pursuing coverage under the insurance policies of its two vegetation management contractors, including under policies where the Utility is listed as an additional insured. Recoveries of any amounts under these policies are uncertain.

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

Insurance Receivable (in millions)	
Balance at December 31, 2015	$-
Accrued insurance recoveries	625
Reimbursements	(50)
Balance at December 31, 2016	$575

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals.

Other Contingencies

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $45 million at December 31, 2016 and $63 million at December 31, 2015. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Consolidated Statements of Income. Disallowances as a result of the CPUC's June 23, 2016 final phase one decision and December 1, 2016 final phase two decision in the Utility's 2015 GT&S rate case, the April 9, 2015 Penalty Decision and the Utility's Pipeline Safety Enhancement Plan are discussed below.

2015 GT&S Rate Case Disallowance of Capital Expenditures

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The decision permanently disallowed a portion of the 2011 through 2014 capital spending in excess of the amount adopted and established various cost caps that will increase the risk of overspend over the current rate case cycle, including new one-way capital balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.

Penalty Decision's Disallowance of Natural Gas Capital Expenditures

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

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

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

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

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

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

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

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of December 31, 2016, the Utility has spent $1.35 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue beyond 2017. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

Environmental Remediation Contingencies

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

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

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

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

The Utility's environmental remediation liability at December 31, 2016 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

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

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Needles, California and is referred to below as the "Topock site." Another station is located near Hinkley, California and is referred to below as the "Hinkley site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

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Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC conducted an additional environmental review of the proposed design and issued a draft environmental impact report for public comment in January 2017. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in mid-2017. After the Utility modifies its design in response to the final report, the Utility will seek approval to begin construction of the new in-situ treatment system in late 2017 or early 2018.

Hinkley Site

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. In November 2015, the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.9 billion (including amounts related to the Topock and Hinkley sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition and cash flows during the period in which they are recorded.

Nuclear Insurance

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

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2016, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $60 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $2 million, as of December 31, 2016.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13.5 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13.5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.

Resolution of Remaining Chapter 11 Disputed Claims

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. In connection with the CPUC approved settlement agreement, on April 12, 2004, the Utility deposited approximately $1.7 billion into escrow for the payment of certain disputed claims, previously collected from customers through rates. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

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

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

At December 31, 2016 and December 31, 2015, respectively, the Consolidated Balance Sheets reflected $236 million and $454 million in net claims within Disputed claims and customer refunds. The cash held in escrow within Restricted cash was zero as of December 31, 2016 and $228 million as of December 31, 2015. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

Purchase Commitments

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2016:

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

Third-Party Power Purchase Agreements

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

Renewable Energy Power Purchase Agreements. In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2016, renewable energy contracts expire at various dates between 2017 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2016, these power purchase agreements expire at various dates between 2017 and 2033.

Other Power Purchase Agreements. The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2016 and 2015, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $35 million and $54 million including accumulated amortization of $148 million and $147 million, respectively. The present value of the future minimum lease payments due under these agreements included $17 million and $19 million in Current Liabilities and $18 million and $35 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2016, QF contracts in operation expire at various dates between 2017 and 2028. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases and electric capacity amounted to $3.5 billion in 2016, $3.5 billion in 2015, and $3.6 billion in 2014.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2017 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.7 billion in 2016, $0.9 billion in 2015, and $1.4 billion in 2014.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2017 and 2025 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $100 million in 2016, $128 million in 2015, and $105 million in 2014.

Other Commitments

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2017 and 2052. At December 31, 2016, the future minimum payments related to these commitments were as follows:

(in millions)	Operating Leases
2017	$ 44
2018	41

2019		39
2020		39
2021		36
Thereafter		168
Total minimum lease payments	$	367

Payments for other commitments related to operating leases amounted to $43 million in 2016, $41 million in 2015, and $42 million in 2014. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

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QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended December 31	September 30	June 30	March 31
2016				
PG&E CORPORATION				
Operating revenues (1)	$4,713	$ 4,810	$ 4,169	$ 3,974
Operating income	1,041	640	401	95
Income tax provision (benefit) (2)	160	70	12	(187)
Net income (3)	696	391	210	110
Income available for common shareholders	692	388	206	107
Comprehensive income	694	391	210	110
Net earnings per common share, basic	1.37	0.77	0.41	0.22
Net earnings per common share, diluted	1.36	0.77	0.41	0.22
Common stock price per share:				
High	62.12	65.39	63.92	59.72
Low	58.04	60.82	56.62	51.29
UTILITY				
Operating revenues				