PG&E Corp
Form 10-Q
July 27, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C., 20549
FORM 10-Q
(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2017

OR

[ ] 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	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

PG&E Corporation	Pacific Gas and Electric Company
77 Beale Street	77 Beale Street
P.O. Box 770000	P.O. Box 770000
San Francisco, California 94177	San Francisco, California 94177

Address of principal executive offices, including zip code

PG&E Corporation	Pacific Gas and Electric Company
(415) 973-1000	(415) 973-7000

Registrant's telephone number, including area code

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:	[X] Yes [ ] No
Pacific Gas and Electric Company:	[X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation:	[X] Yes [ ] No
Pacific Gas and Electric Company:	[X] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company”, and “emerging growth company” in Rule 12b-2 of the Exchange Act.

PG&E Corporation:	[X] Large accelerated filer	[ ] Accelerated filer
	[ ] Non-accelerated filer (Do not check if a smaller reporting company)	
	[ ] Smaller reporting company	[ ] Emerging growth company
Pacific Gas and Electric Company:	[ ] Large accelerated filer	[ ] Accelerated filer
	[X] Non-accelerated filer (Do not check if a smaller reporting company)	
	[ ] Smaller reporting company	[ ] Emerging growth company

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

PG&E Corporation:	[ ]
	[ ]

Pacific Gas and Electric
Company:

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
PG&E Corporation: [ ] Yes [X] No

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Pacific Gas and Electric Company:	[ ] Yes [X] No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding as of July 21, 2017:	
PG&E Corporation:	512,821,658
Pacific Gas and Electric Company:	264,374,809

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PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2017

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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 and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2016
2017 Q1 Form 10-Q	PG&E Corporation and Pacific Gas and Electric Company's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2017
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
CP	cathodic protection
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DER	distributed energy resources
DIDF	Distribution Investment Deferral Framework
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
DRP	electric distribution resources plan
DTSC	Department of Toxic Substances Control
EDA	equity distribution agreement
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
GWH	gigawatt-hours
IOU(s)	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 Item 2, of this Form 10-Q
MOU	memorandum of understanding
NAV	net asset value
NDCTP	Nuclear Decommissioning Cost Triennial Proceedings
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering

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NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
OEM	original equipment manufacturer
OES	State of California Office of Emergency Services
OII	order instituting investigation
OIR	order instituting rulemaking
ORA	Office of Ratepayer Advocates
PCIA	Power Charge Indifference Adjustment
PD	proposed decision
PFM	petition for modification
PHMSA	Pipeline and Hazardous Materials Safety Administration
QF	qualifying facility
Regional Board	California Regional Water Quality Control Board, Lahontan Region
RFO	requests for offers
ROE	return on equity
RPS	renewable portfolio standards
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)
WECC	Western Electricity Coordinating Council
WEMA	Wildfire Expense Memorandum Account
Westinghouse	Westinghouse Electric Company, LLC

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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2017	2016	2017	2016
Operating Revenues				
Electric	$3,323	$3,465	$6,388	$6,596
Natural gas	927	704	2,130	1,547
Total operating revenues	4,250	4,169	8,518	8,143
Operating Expenses				
Cost of electricity	1,123	1,156	1,970	2,106
Cost of natural gas	121	75	446	297
Operating and maintenance	1,546	1,838	3,050	3,848
Depreciation, amortization, and decommissioning	712	699	1,424	1,396
Total operating expenses	3,502	3,768	6,890	7,647
Operating Income	748	401	1,628	496
Interest income	8	5	13	9
Interest expense	(225)	(207)	(443)	(410)
Other income, net	13	23	34	50
Income Before Income Taxes	544	222	1,232	145
Income tax provision (benefit)	134	12	243	(175)
Net Income	410	210	989	320
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income Available for Common Shareholders	$406	$206	$982	$313
Weighted Average Common Shares Outstanding, Basic	511	497	510	495
Weighted Average Common Shares Outstanding, Diluted	513	498	512	497
Net Earnings Per Common Share, Basic	$0.79	$0.41	$1.93	$0.63
Net Earnings Per Common Share, Diluted	$0.79	$0.41	$1.92	$0.63
Dividends Declared Per Common Share	$0.53	$0.49	$1.02	$0.95

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2017	2016	2017	2016
Net Income	$410	$210	$989	$320
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations				
(net of taxes of $0, $0, $0 and $0, at respective dates)	1	-	1	-
Total other comprehensive income (loss)	1	-	1	-
Comprehensive Income	411	210	990	320
Preferred stock dividend requirement of subsidiary	4	4	7	7
Comprehensive Income Attributable to				
Common Shareholders	$407	$206	$983	$313

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions)	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	$178	$177
Restricted cash	7	7
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $60 and $58 at respective dates)	1,208	1,252
Accrued unbilled revenue	988	1,098
Regulatory balancing accounts	1,565	1,500
Other	760	801
Regulatory assets	522	423
Inventories:		
Gas stored underground and fuel oil	132	117
Materials and supplies	369	346
Income taxes receivable	93	160
Other	249	283
Total current assets	6,071	6,164
Property, Plant, and Equipment		
Electric	53,692	52,556
Gas	18,555	17,853
Construction work in progress	2,311	2,184
Other	2	2
Total property, plant, and equipment	74,560	72,595
Accumulated depreciation	(22,924)	(22,014)
Net property, plant, and equipment	51,636	50,581
Other Noncurrent Assets		
Regulatory assets	8,311	7,951
Nuclear decommissioning trusts	2,733	2,606
Income taxes receivable	70	70
Other	1,234	1,226
Total other noncurrent assets	12,348	11,853
TOTAL ASSETS	$70,055	$68,598

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions, except share amounts)	2017	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$1,180	$1,516
Long-term debt, classified as current	700	700
Accounts payable:		
Trade creditors	1,389	1,495
Regulatory balancing accounts	871	645
Other	423	433
Disputed claims and customer refunds	238	236
Interest payable	220	216
Other	1,927	2,323
Total current liabilities	6,948	7,564
Noncurrent Liabilities		
Long-term debt	16,616	16,220
Regulatory liabilities	7,125	6,805
Pension and other postretirement benefits	2,687	2,641
Asset retirement obligations	4,675	4,684
Deferred income taxes	10,753	10,213
Other	2,360	2,279
Total noncurrent liabilities	44,216	42,842
Commitments and Contingencies (Note 9)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 512,220,726 and 506,891,874 shares outstanding at respective dates	12,442	12,198
Reinvested earnings	6,205	5,751
Accumulated other comprehensive loss	(8)	(9)
Total shareholders' equity	18,639	17,940
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	18,891	18,192
TOTAL LIABILITIES AND EQUITY	$70,055	$68,598

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Six Months Ended June 30,	
(in millions)	2017	2016
Cash Flows from Operating Activities		
Net income	$989	$320
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,424	1,396
Allowance for equity funds used during construction	(34)	(54)
Deferred income taxes and tax credits, net	516	350
Disallowed capital expenditures	47	425
Other	121	179
Effect of changes in operating assets and liabilities:		
Accounts receivable	111	(75)
Butte-related insurance receivable	54	(263)
Inventories	(38)	(30)
Accounts payable	19	179
Butte-related third-party claims	(116)	349
Income taxes receivable/payable	67	(79)
Other current assets and liabilities	(92)	(7)
Regulatory assets, liabilities, and balancing accounts, net	(353)	(769)
Other noncurrent assets and liabilities	41	(106)
Net cash provided by operating activities	2,756	1,815
Cash Flows from Investing Activities		
Capital expenditures	(2,474)	(2,651)
Proceeds from sales and maturities of nuclear decommissioning trust investments	794	721
Purchases of nuclear decommissioning trust investments	(817)	(762)
Other	8	6
Net cash used in investing activities	(2,489)	(2,686)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $3 at respective dates	(339)	257
Short-term debt financing	250	250
Short-term debt matured	(250)	-
Proceeds from issuance of long-term debt, net of discount and issuance costs of $11 and $6 at respective dates	734	594
Long-term debt matured or repurchased	(345)	-
Common stock issued	247	289
Common stock dividends paid	(488)	(440)
Other	(75)	(13)
Net cash provided by (used in) financing activities	(266)	937

Net change in cash and cash equivalents	1	66
Cash and cash equivalents at January 1	177	123
Cash and cash equivalents at June 30	$178	$189

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(395)	$(357)
Income taxes, net	68	54
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$271	$244
Capital expenditures financed through accounts payable	268	309
Noncash common stock issuances	10	10

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Operating Revenues				
Electric	$3,324	$3,465	$6,391	$6,597
Natural gas	926	704	2,130	1,547
Total operating revenues	4,250	4,169	8,521	8,144
Operating Expenses				
Cost of electricity	1,123	1,156	1,970	2,106
Cost of natural gas	121	75	446	297
Operating and maintenance	1,545	1,837	3,049	3,848
Depreciation, amortization, and decommissioning	712	700	1,424	1,396
Total operating expenses	3,501	3,768	6,889	7,647
Operating Income	749	401	1,632	497
Interest income	7	4	12	8
Interest expense	(222)	(204)	(438)	(405)
Other income, net	11	21	28	45
Income Before Income Taxes	545	222	1,234	145
Income tax provision (benefit)	136	13	256	(172)
Net Income	409	209	978	317
Preferred stock dividend requirement	4	4	7	7
Income Available for Common Stock	$405	$205	$971	$310

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2017	2016	2017	2016
Net Income	$409	$209	$978	$317
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations				
(net of taxes of $0, $0, $0 and $0, at respective dates)	-	1	1	1
Total other comprehensive income (loss)	-	1	1	1
Comprehensive Income	$409	$210	$979	$318

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$57	$71
Restricted cash	7	7
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $60 and $58 at respective dates)	1,208	1,252
Accrued unbilled revenue	988	1,098
Regulatory balancing accounts	1,565	1,500
Other	758	801
Regulatory assets	522	423
Inventories:		
Gas stored underground and fuel oil	132	117
Materials and supplies	369	346
Income taxes receivable	84	159
Other	248	282
Total current assets	5,938	6,056
Property, Plant, and Equipment		
Electric	53,692	52,556
Gas	18,555	17,853
Construction work in progress	2,311	2,184
Total property, plant, and equipment	74,558	72,593
Accumulated depreciation	(22,922)	(22,012)
Net property, plant, and equipment	51,636	50,581
Other Noncurrent Assets		
Regulatory assets	8,311	7,951
Nuclear decommissioning trusts	2,733	2,606
Income taxes receivable	70	70
Other	1,111	1,110
Total other noncurrent assets	12,225	11,737
TOTAL ASSETS	$69,799	$68,374

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions, except share amounts)	2017	2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$1,180	$1,516
Long-term debt, classified as current	700	700
Accounts payable:		
Trade creditors	1,389	1,494
Regulatory balancing accounts	871	645
Other	468	453
Disputed claims and customer refunds	238	236
Interest payable	218	214
Other	1,664	2,072
Total current liabilities	6,728	7,330
Noncurrent Liabilities		
Long-term debt	16,267	15,872
Regulatory liabilities	7,125	6,805
Pension and other postretirement benefits	2,592	2,548
Asset retirement obligations	4,675	4,684
Deferred income taxes	11,063	10,510
Other	2,306	2,230
Total noncurrent liabilities	44,028	42,649
Commitments and Contingencies (Note 9)		
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	8,240	8,050
Reinvested earnings	9,220	8,763
Accumulated other comprehensive income	3	2
Total shareholders' equity	19,043	18,395
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$69,799	$68,374

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Six Months Ended June 30,	
(in millions)	2017	2016
Cash Flows from Operating Activities		
Net income	$978	$317
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,424	1,396
Allowance for equity funds used during construction	(34)	(54)
Deferred income taxes and tax credits, net	534	352
Disallowed capital expenditures	47	425
Other	127	144
Effect of changes in operating assets and liabilities:		
Accounts receivable	113	(76)
Butte-related insurance receivable	54	(263)
Inventories	(38)	(30)
Accounts payable	45	190
Butte-related third-party claims	(116)	349
Income taxes receivable/payable	75	(78)
Other current assets and liabilities	(72)	(5)
Regulatory assets, liabilities, and balancing accounts, net	(353)	(769)
Other noncurrent assets and liabilities	40	(95)
Net cash provided by operating activities	2,824	1,803
Cash Flows from Investing Activities		
Capital expenditures	(2,474)	(2,651)
Proceeds from sales and maturities of nuclear decommissioning trust investments	794	721
Purchases of nuclear decommissioning trust investments	(817)	(762)
Other	8	6
Net cash used in investing activities	(2,489)	(2,686)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $3 at respective dates	(339)	257
Short-term debt financing	250	250
Short-term debt matured	(250)	-
Proceeds from issuance of long-term debt, net of discount and issuance costs of $11 and $6 at respective dates	734	594
Long-term debt matured or repurchased	(345)	-
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(514)	(423)
Equity contribution from PG&E Corporation	190	280
Other	(68)	(7)

Net cash provided by (used in) financing activities	(349)	944
Net change in cash and cash equivalents	(14)	61
Cash and cash equivalents at January 1	71	59
Cash and cash equivalents at June 30	$57	$120

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(390)	$(352)
Income taxes, net	76	54
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$268	$309

See accompanying Notes to the Condensed Consolidated Financial Statements.

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

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 quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed 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 Condensed 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 Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2016 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2016 Form 10-K. This quarterly report should be read in conjunction with the 2016 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, insurance recoveries, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Condensed 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 during the period in which such change occurred.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2016 Form 10-K.

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 has a controlling interest or was the primary beneficiary of any of these VIEs at June 30, 2017, the Utility 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 June 30, 2017, it did not consolidate any of them.

Asset Retirement Obligations

Detailed studies of the cost to decommission the Utility’s nuclear generation facilities are conducted every three years in conjunction with the NDCTP. On May 25, 2017, the CPUC issued a final decision in the 2015 NDCTP adopting a nuclear decommissioning cost estimate of $1.1 billion for Humboldt Bay, corresponding to the Utility’s request, and $2.4 billion for Diablo Canyon, compared to the Utility’s request of $3.8 billion, or 64 percent of its request. On an aggregate basis, the final decision adopted a $3.5 billion total nuclear decommissioning cost estimate, compared to $4.8 billion requested by the Utility. Compared to the Utility’s estimated cost to decommission Diablo Canyon, the final decision adopts assumptions which lower costs for large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility can seek recovery of these costs in the 2018 NDCTP. The CPUC’s final decision resulted in a $66 million reduction to the ARO on the Condensed Consolidated Balance Sheets related to the assumed length of the wet cooling period of spent nuclear fuel after plant shut down.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.4 billion at June 30, 2017, and $3.5 billion at December 31, 2016. 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.

Pension and Other Post-retirement Benefits

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

The net periodic benefit costs reflected in PG&E Corporation’s Condensed Consolidated Financial Statements for the three and six months ended June 30, 2017 and 2016 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Service cost for benefits earned	$ 118	$ 113	$ 15	$ 13
Interest cost	178	179	19	19
Expected return on plan assets	(192)	(207)	(25)	(27)

Amortization of prior service cost	(2)	2	4	4
Amortization of net actuarial loss	5	6	1	1
Net periodic benefit cost	107	93	14	10
Regulatory account transfer (1)	(23)	(8)	-	-
Total	$ 84	$ 85	$ 14	$ 10

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

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Service cost for benefits earned	$ 236	$ 226	$ 30	$ 26
Interest cost	357	358	38	38
Expected return on plan assets	(385)	(414)	(49)	(54)
Amortization of prior service cost	(4)	4	8	8
Amortization of net actuarial loss	11	12	2	2
Net periodic benefit cost	215	186	29	20
Regulatory account transfer (1)	(46)	(17)	-	-
Total	$ 169	$ 169	$ 29	$ 20

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

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

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (Loss)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended June 30, 2017		
Beginning balance	$ (25)	$ 16	$ (9)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost (net of taxes of $1 and $1, respectively)	(1)	3	2
Amortization of net actuarial loss (net of taxes of $2 and $1, respectively)	3	-	3
Regulatory account transfer (net of taxes of $1 and $2, respectively)	(2)	(2)	(4)
Net current period other comprehensive gain (loss)	-	1	1
Ending balance	$ (25)	$ 17	$ (8)

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended June 30, 2016		
Beginning balance	$(23)	$ 16	$ (7)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost (net of taxes of $1 and $1, respectively)	1	3	4
Amortization of net actuarial loss (net of taxes of $2, and $1, respectively)	4	-	4
Regulatory account transfer (net of taxes of $3 and $2, respectively)	(5)	(3)	(8)
Net current period other comprehensive gain (loss)	-	-	-
Ending balance	$(23)	$ 16	$ (7)

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the “Pension and Other Postretirement Benefits” table above for additional details.)

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(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Six Months Ended June 30, 2017		
Beginning balance	$(25)	$ 16	$ (9)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $2 and $3, respectively)	(2)	5	3
Amortization of net actuarial loss			
(net of taxes of $5 and $1, respectively)	6	1	7
Regulatory account transfer			
(net of taxes of $3 and $4, respectively)	(4)	(5)	(9)
Net current period other comprehensive gain (loss)	-	1	1
Ending balance	$(25)	$ 17	$ (8)

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the “Pension and Other Postretirement Benefits” table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Six Months Ended June 30, 2016		
Beginning balance	$(23)	$ 16	$(7)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $2 and $3, respectively)	2	5	7
Amortization of net actuarial loss			
(net of taxes of $4 and $1, respectively)	8	1	9
Regulatory account transfer			
(net of taxes of $6 and $4, respectively)	(10)	(6)	(16)
Net current period other comprehensive gain (loss)	-	-	-
Ending balance	$(23)	$ 16	$(7)

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the “Pension and Other Postretirement Benefits” table above for additional details.)

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

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 statements of cash flows. PG&E Corporation and the Utility have adopted this standard as of the fourth quarter of 2016.

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 Condensed Consolidated Statements of Cash Flows for PG&E Corporation and the Utility for the prior periods presented were retrospectively adjusted. This change resulted in an increase to cash flows from operating activities and a decrease to cash flows from financing activities of $34 million for the six months ended June 30, 2016.

Accounting Standards Issued But Not Yet Adopted

Presentation of Net Periodic Pension Cost

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715), which amends the existing guidance relating to the presentation of net periodic pension cost and net periodic postretirement benefit cost. The amendment requires an employer to disaggregate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. In addition, on a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018, with early adoption permitted. Although PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on the Condensed Consolidated Financial Statements and related disclosures, it is not expected to have a material impact to financial results.

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. As of June 30, 2017, PG&E Corporation and the Utility held immaterial balances within restricted cash. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on the Condensed Consolidated Statements of Cash Flows and related disclosures.

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 and will be applied on a modified retrospective basis. PG&E Corporation and the Utility are still evaluating the impact the guidance will have on the Condensed 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, measurement, presentation, and disclosure of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts. These investments are classified as "available-for-sale" and gains or losses are refundable, or recoverable, from customers through rates. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility do not anticipate a material impact to the Condensed Consolidated Financial Statements and related disclosures as a result of this ASU.

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, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. PG&E Corporation and the Utility intend to use the modified retrospective method when adopting the new standard on January 1, 2018. PG&E Corporation and the Utility are currently reviewing all revenue streams and evaluating the impact the guidance will have on the Condensed Consolidated Financial Statements and related disclosures.

While the Utility expects that most of its revenue will be included in the scope of ASU 2014-09, it has not yet fully completed its evaluation. The majority of the Utility's revenue, including energy provided to customers, is from tariff offerings that provide natural gas or electricity without a defined contractual term. For such arrangements, the Utility generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity or natural gas supplied and billed in that period (including unbilled revenues) and the adoption of the new guidance will not result in a significant shift in the timing of revenue recognition for such sales. 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. Additionally, the Utility expects more detailed revenue disclosures related to the nature, timing and uncertainty in revenues upon adoption of ASU 2014-09.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets and Liabilities

Long-term regulatory assets and liabilities are comprised of the following:

(in millions)	Asset Balance at June 30, 2017	December 31, 2016
Deferred income taxes	$4,195	$ 3,859
Pension benefits	2,467	2,429
Environmental compliance costs	770	778
Utility retained generation	342	364
Price risk management	84	92
Unamortized loss, net of gain, on reacquired debt	69	76
Other	384	353
Total long-term regulatory assets	$8,311	$ 7,951

(in millions)	Liability Balance at June 30, 2017	December 31, 2016
Cost of removal obligations	$5,342	$ 5,060

Recoveries in excess of AROs	661	626
Public purpose programs	554	567
Other	568	552
Total long-term regulatory liabilities	$7,125	$ 6,805

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2016 Form 10-K.

Regulatory Balancing Accounts

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

(in millions)	Receivable Balance at June 30, 2017	December 31, 2016
Electric distribution	$285	$ 132
Electric transmission	212	244
Utility generation	117	48
Gas distribution and transmission	433	541
Energy procurement	-	132
Public purpose programs	129	106
Other	389	297
Total regulatory balancing accounts receivable	$1,565	$ 1,500

(in millions)	Payable Balance at June 30, 2017	December 31, 2016
Electric transmission	$171	$ 99
Gas distribution and transmission	-	48
Energy procurement	86	13
Public purpose programs	376	264
Other	238	221
Total regulatory balancing accounts payable	$871	$ 645

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2016 Form 10-K.

NOTE 4: DEBT

Revolving Credit Facilities and Commercial Paper Program

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at June 30, 2017:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2022	$300	(1)	$ -	$ -	$ 300
Utility	April 2022	3,000	(2)	42	681	2,277
Total revolving credit facilities		$3,300		$ 42	$ 681	$ 2,577

(1) Includes a $50 million lender commitment to the letter of credit sublimit 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 sublimit and a $75 million commitment for swingline loans.

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

Other Short-term Borrowings

In February 2017, the Utility's $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid.

Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 22, 2018. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Senior Notes Issuances

In March 2017, the Utility issued $400 million principal amount of 3.30% Senior Notes due March 15, 2027 and $200 million principal amount of 4.00% Senior Notes due December 1, 2046. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Pollution Control Bonds

In June 2017, the Utility repurchased and retired $345 million principal amount of pollution control bonds Series 2004 A through D. Additionally in June 2017, the Utility remarketed three series of pollution control bonds, previously held in treasury, totaling $145 million in principal amount. Series 2008 F and 2010 E bear interest at 1.75% per annum and mature on November 1, 2026. Series 2008 G bears interest at 1.05% per annum and matures on December 1, 2018.

At June 30, 2017, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.84% to 0.95%. At June 30, 2017, the interest rates on the $149 million principal amount of pollution control bonds Series 2009 A and B, and the related loan agreements, were 0.88%.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the six months ended June 30, 2017 were as follows:

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2016	$ 18,192	$ 18,395

Comprehensive income	990	979
Equity contributions	-	190
Common stock issued	257	-
Share-based compensation	(13)	-
Common stock dividends declared	(528)	(514)
Preferred stock dividend requirement	-	(7)
Preferred stock dividend requirement of subsidiary	(7)	-
Balance at June 30, 2017	$ 18,891	$ 19,043

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate price of up to $275 million. During the six months ended June 30, 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $28.4 million, net of commissions paid of $0.2 million. There were no issuances under the February 2017 EDA for the three months ended June 30, 2017. As of June 30, 2017, the remaining sales available under this agreement were $246.3 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the six months ended June 30, 2017, 4.9 million shares were issued for cash proceeds of $218 million under these plans.

NOTE 6: 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2017	2016	2017	2016
Income available for common shareholders	$406	$206	$982	$313
Weighted average common shares outstanding, basic	511	497	510	495
Add incremental shares from assumed conversions:				
Employee share-based compensation	2	1	2	2
Weighted average common shares outstanding, diluted	513	498	512	497
Total earnings per common share, diluted	$0.79	$0.41	$1.92	$0.63

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 7: DERIVATIVES

Use of Derivative Instruments

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

Derivatives are presented in the Utility's Condensed Consolidated Balance Sheets recorded at fair value and 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 PG&E Corporation's and the Utility's Condensed 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 Condensed 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 Condensed Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

Volume of Derivative Activity

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

		Contract Volume at	
		June 30,	December 31,
Underlying Product	Instruments	2017	2016
Natural Gas (1) (MMBtus (2))	Forwards, Futures and Swaps	288,947,618	323,301,331
	Options	76,490,259	96,602,785
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	3,706,674	3,287,397
	Congestion Revenue Rights (3)	254,357,332	278,143,281

(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 June 30, 2017, 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	$56	$ (10)	$ 16	$ 62
Other noncurrent assets – other	123	(4)	-	119
Current liabilities – other	(52)	10	7	(35)
Noncurrent liabilities – other	(88)	4	9	(75)
Total commodity risk	$39	$ -	$ 32	$ 71

At December 31, 2016, 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	$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

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

	Commodity Risk			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2017	2016	2017	2016
Unrealized gain (loss) - regulatory assets and liabilities (1)	$(4)	$ 66	$(52)	$59
Realized gain (loss) - cost of electricity (2)	1	(12)	(4)	(41)
Realized loss - cost of natural gas (2)	(3)	(5)	(4)	(6)
Net commodity risk	$(6)	$ 49	$(60)	$12

(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 Condensed 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 Condensed 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 June 30, 2017, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

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

	Balance at	
	June 30,	December 31,
(in millions)	2017	2016
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$(1)	$ (24)
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)	$ (1)

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

NOTE 8: 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.

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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 June 30, 2017				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$121	$-	$-	$ -	$121
Nuclear decommissioning trusts					
Short-term investments	10	-	-	-	10
Global equity securities	1,786	-	-	-	1,786
Fixed-income securities	740	571	-	-	1,311
Assets measured at NAV	-	-	-	-	16
Total nuclear decommissioning trusts (2)	2,536	571	-	-	3,123
Price risk management instruments (Note 7)					
Electricity	5	9	158	3	175
Gas	2	5	-	(1)	6
Total price risk management instruments	7	14	158	2	181
Rabbi trusts					
Fixed-income securities	-	63	-	-	63
Life insurance contracts	-	71	-	-	71
Total rabbi trusts	-	134	-	-	134
Long-term disability trust					
Short-term investments	5	-	-	-	5
Assets measured at NAV	-	-	-	-	156
Total long-term disability trust	5	-	-	-	161
TOTAL ASSETS	$2,669	$719	$158	$ 2	$3,720
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$12	$17	$110	$ (30)	$109
Gas	-	1	-	-	1
TOTAL LIABILITIES	$12	$18	$110	$ (30)	$110

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

(2) Represents amount before deducting $390 million, primarily related to deferred taxes on appreciation of investment value.

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(in millions)	Fair Value Measurements At December 31, 2016 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 in the 2016 Form 10-K)					
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 in the 2016 Form 10-K)					
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.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the six months ended June 30, 2017 and 2016.

Trust Assets

Assets Measured at Fair Value

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

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

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

Assets Measured at NAV Using Practical Expedient

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

Price Risk Management Instruments

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

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

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

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

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to PG&E Corporation's 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.

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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 7 above.)

(in millions)	Fair Value at At June 30, 2017		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$158	$ 37	Market approach	CRR auction prices	$(11.88) - 10.54
Power purchase agreements	$-	$ 73	Discounted cash flow	Forward prices	$18.81 - 38.80

(1) Represents price per megawatt-hour

(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

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the three and six months ended June 30, 2017 and 2016:

	Price Risk Management Instruments	
(in millions)	2017	2016
Asset (liability) balance as of April 1	$ 49	$ 75
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(1)	(9)
Asset (liability) balance as of June 30	$ 48	$ 66

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

(in millions)	Price Risk Management Instruments 2017	2016
Asset (liability) balance as of January 1	$ 55	$ 89
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(7)	(23)
Asset (liability) balance as of June 30	$ 48	$ 66

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

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at June 30, 2017 and December 31, 2016, 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 June 30, 2017 and December 31, 2016.

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 June 30, 2017		At December 31, 2016	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
PG&E Corporation	$348	$352	$348	$352
Utility	16,208	18,583	15,813	17,790

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 June 30, 2017				
Nuclear decommissioning trusts				
Short-term investments	$ 10	$-	$-	$10
Global equity securities	527	1,277	(2)	1,802
Fixed-income securities	1,260	57	(6)	1,311
Total (1)	$ 1,797	$1,334	$(8)	$3,123
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

(1) Represents amounts before deducting $390 million and $333 million at June 30, 2017 and December 31, 2016, 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

	June 30, 2017
Less than 1 year	$6
1–5 years	452
5–10 years	308
More than 10 years	545
Total maturities of fixed-income securities	$1,311

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$324	$282	$794	$721
Gross realized gains on securities held as available-for-sale	13	4	42	9
Gross realized losses on securities held as available-for-sale	(3)	(1)	(8)	(3)

NOTE 9: 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. A gain contingency is recorded in the period in which all uncertainties have been resolved. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. For more information, see Note 13 “Contingencies and Commitments” of the Notes to the Consolidated Financial Statements in the 2016 Form 10-K. 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

Butte Fire Litigation and Regulatory Citations

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.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California 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 June 30, 2017, approximately 60 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 2,050 individual plaintiffs representing approximately 1,180 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. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may increase in the future. The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, among other claims.

Also, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

Two trials have been scheduled in connection with the Butte fire. On April 14, 2017, the Superior Court of California for Sacramento County found that six “preference” households (households that include individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling) are entitled to a trial. The trial has been scheduled to commence on August 14, 2017 in Sacramento.

The court also set a representative trial date for October 30, 2017 in Sacramento. A representative trial is a trial where the parties agree, or the court decides, on plaintiffs who are "representative" of broader groups of plaintiffs such that the trial may assist the parties in settling other cases after obtaining verdicts in the representative trial.

Estimated Losses from Third-Party Claims

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. On June 22, 2017, the Superior Court for the County of Sacramento ruled on a motion of several plaintiffs and found that the Utility is liable for inverse condemnation. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding, others could file lawsuits and make similar claims. 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. While the Utility believes it was not negligent, 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 in connection with the Butte fire. 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 certain other damages, but does not include punitive damages for which the Utility could be liable. In addition, while this amount includes the Utility's early assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility currently does not have sufficient information to reasonably estimate any liability it may have for these additional claims.

The Utility currently is 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, results from the ongoing mediation and settlement process, review of potential claims from the OES and the County of Calaveras, outcomes of future court or jury decisions, and information about damages, including punitive damages, that the Utility could be liable for, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

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

Loss Accrual (in millions)	
Balance at December	$ -

31, 2015	
Accrued losses	750
Payments (1)	(60)
Balance at December 31, 2016	$690
Accrued losses	-
Payments (1)	(116)
Balance at June 30, 2017	$574

(1) As of June 30, 2017 the Utility entered into settlement agreements in connection with the Butte fire corresponding to approximately $380 million of which $176 million has been paid by the Utility.

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $54 million in connection with the Butte fire. For the three months and six months ended June 30, 2017, the Utility has incurred legal expenses in connection with the Butte fire of $17 and $27 million, respectively.

Loss Recoveries

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. Through June 30, 2017, the Utility recorded $646 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, in the second quarter of 2017, the Utility received $32 million of reimbursements from the insurance policies of one of its vegetation management contractors (excluded from the table below). Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

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

Insurance Receivable (in millions)	
Balance at December 31, 2015	$-
Accrued insurance recoveries	625
Reimbursements	(50)
Balance at December 31, 2016	$575
Accrued insurance recoveries	21
Reimbursements	(75)
Balance at June 30, 2017	$521

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.

If the Utility's ultimate liability were to exceed amounts recoverable under its liability insurance coverage and from third parties, the Utility would expect to seek authorization from the CPUC to recover any excess amounts from customers. On July 26, 2017, the Utility filed an application with the CPUC requesting to establish a Wildfire Expense Memorandum Account to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date. The resolution of claims, the recoveries from other potentially responsible parties, and future regulatory proceedings, if any, could extend over a number of years.

Regulatory Citations

On April 25, 2017, the SED issued two citations to the Utility in connection with the Butte fire, totaling $8.3 million. The SED's investigation found that neither the Utility nor its vegetation management contractors took appropriate steps to prevent the gray pine from leaning and contacting the Utility's electric line, which created an unsafe and dangerous condition that resulted in that tree leaning and making contact with the electric line, thus causing a fire. The Utility paid the citations in June 2017.

CPUC Matters

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

On March 28, 2017, the Utility, the Cities of San Bruno and San Carlos, the ORA, the SED, and TURN (together, the "parties") jointly submitted to the CPUC a settlement agreement in connection with the order instituting an investigation into the Utility's compliance with the CPUC's ex parte communication rules and jointly moved for its approval. As previously disclosed, the Utility has already incurred a disallowance of $72 million imposed by the CPUC in connection with certain ex parte communications in the Utility's 2015 GT&S rate case. Of the $72 million total GT&S ex parte disallowance, $57 million was recognized in 2016 and the remaining $15 million was recognized in the first quarter of 2017.

Pursuant to the settlement agreement, the Utility agreed to a total financial remedy of $86.5 million comprised of: (1) a $1 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over its next GRC cycle (i.e., the GRC following the 2017 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.

On June 19, 2017, the assigned ALJ issued a ruling requesting that the Utility file a supplemental briefing on the number of admitted violations and whether or not those violations were continuing. The Utility filed the brief on June 23, 2017, admitting that 12 communications were violations of the CPUC's ex parte rules and noting that the additional communications at issue in the proceeding had been included by other parties and the Utility did not agree they constituted violations. The Utility did not admit that any particular violation was continuing, which would be decided by the CPUC if there were no settlement.

The CPUC may accept, reject, or modify the terms of the settlement agreement, including imposing additional penalties on the Utility. The statutory deadline for this proceeding was extended from May 17, 2017 to December 29, 2017. The Utility is unable to predict the outcome of this proceeding.

At June 30, 2017, PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets include a $13 million accrual for the portions of the settlement agreement that would be payable to the California General Fund and the Cities of San Bruno and San Carlos. In accordance with accounting rules, adjustments related to revenue requirements would be recorded in the periods in which they are incurred.

For more information about the proceeding, see Note 13 "Contingencies and Commitments" of the Notes to the Consolidated Financial Statements in the 2016 Form 10-K.

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Order Instituting an Investigation into the Utility’s Safety Culture

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

On May 8, 2017, the CPUC President released the consultant's report, accompanied by a scoping memo and ruling. The scoping memo establishes a second phase in this OII in which the CPUC will evaluate the safety recommendations of the consultant which may lead to the CPUC’s adoption of the recommendations in the report, in whole or in part. This phase of the proceeding will also consider all necessary measures, including, but not limited to, a reduction of the Utility’s return on equity until any recommendations adopted by the CPUC are implemented. The Utility plans to adopt the vast majority of the consultant's recommendations and to have completed most of the agreed-upon recommendations by the middle of 2018. A prehearing conference has been scheduled for August 1, 2017. Under the current schedule, the Utility’s testimony is expected to occur in the fourth quarter of 2017 with other parties’ testimony and evidentiary hearings expected in the first quarter of 2018.

PG&E Corporation and the Utility are unable to predict the outcome of this proceeding, including whether additional fines, penalties, or other ratemaking tools will ultimately be adopted by the CPUC, and whether the CPUC will require that a portion of return on equity for the Utility be dependent on making safety progress as the CPUC may define in this proceeding.

Natural Gas Transmission Pipeline Rights-of-Way

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

Potential Safety Citations

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. There are a number of audit findings, as well as other potential violations identified through various investigations and the Utility's self-reported non-compliance with laws and regulations, on which the SED has yet to act. This includes the Utility's February 2017 self-report related to customer service representatives who handle gas emergency calls that was not timely submitted to the CPUC. The Utility believes it is probable that the SED will impose penalties or take other enforcement action with respect to some or all of these violations. 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.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED also 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 SED also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The SED historically has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. The CPUC can also issue an OII and possible additional fines even after the SED has issued a citation. 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.

Federal Investigations

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. The utility is cooperating with this investigation. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

Other Matters

PG&E Corporation and the Utility are subject to various claims, lawsuits, and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under “Enforcement and Litigation Matters”) totaled $43 million at June 30, 2017 and $45 million at December 31, 2016. These amounts are included in Other current liabilities in the Condensed 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

In May 2017, the Utility filed a settlement agreement with the CPUC related to the recovery of license renewal costs and cancelled project costs within its pending application to retire Diablo Canyon Power Plant. The settlement agreement allows for recovery from customers of $18.6 million of the total license renewal project cost of $53 million evenly over an 8-year period beginning January 1, 2018. Related to cancelled project costs, the settlement allows for recovery from customers of 100% of the direct costs incurred prior to June 30, 2016 and 25% recovery of direct costs incurred after June 30, 2016. During the three and six months ended June 30, 2017, the Utility incurred charges of $47 million related to settlement agreement, of which $24 million is for cancelled projects and $23 million is for disallowed license renewal costs.

In addition, the Utility is subject to various cost caps within its rate cases that increase the risk of overspend throughout the rate case cycles. 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 related to its 2015 GT&S rate case. PG&E Corporation and the Utility would 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 Condensed Consolidated Statements of Income. For more information, see Note 13 “Contingencies and Commitments” of the Notes to the Consolidated Financial Statements in the 2016 Form 10-K.

Environmental Remediation Contingencies

The Utility’s environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is composed of the following:

	Balance at	
	June 30,	December 31,
(in millions)	2017	2016
Topock natural gas compressor station (1)	$313	$ 299
Hinkley natural gas compressor station (1)	128	135
Former manufactured gas plant sites owned by the Utility or third parties	319	285
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	131	131
Fossil fuel-fired generation facilities and sites	124	108
Total environmental remediation liability	$1,015	$ 958

(1) See “Natural Gas Compressor Station Sites” below.

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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 June 30, 2017 reflects its best estimate of probable future costs associated with its final remediation plans. 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 the Utility's future financial condition and cash flows.

At June 30, 2017, the Utility expected to recover $718 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. Some of the Utility's environmental remediation liability, such as the environmental remediation costs associated with the Hinkley site discussed below, will not be recovered in rates.

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.

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 late 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 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 by as much as $1.0 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 maintains multiple insurance policies through NEIL and EMANI, covering nuclear or non- nuclear events at the Utility’s two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a maximum aggregate annual retrospective premium obligation of approximately $58 million. EMANI provides $200 million for any one accident and in the annual aggregate the excess of the combined amount recoverable under the Utility’s NEIL policies. For more information about the Utility’s nuclear insurance coverage, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2016 Form 10-K.

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. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2016, the Consolidated Balance Sheets reflected $236 million in net claims within Disputed claims and customer refunds. There were no significant changes to this balance during the six months ended June 30, 2017. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

Tax Matters

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of audits. As of June 30, 2017, 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.

Gain Contingencies

Litigation Related to the San Bruno Accident

As of June 30, 2017, there were seven shareholder derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by certain current and former officers and directors (the "Individual Defendants"), among other claims. Four of the cases were consolidated as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo (the "Court"). 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. (the "Additional Derivative Cases").

On March 15, 2017, the parties in the San Bruno Fire Derivative Cases filed with the Court a settlement that they reached to resolve the consolidated shareholder derivative lawsuit and certain additional claims against the Individual Defendants. Pursuant to the settlement stipulation, subject to certain conditions: (1) the Individual Defendants' directors and officers liability insurance carriers will pay $90 million to PG&E Corporation within 11 business days of the entry of the judgment approving settlement in the San Bruno Fire Derivative Cases, (2) PG&E Corporation and the Utility will implement certain corporate governance therapeutics for five years, and (3) the Utility will implement certain gas operations therapeutics and maintain certain of them for three years, at an estimated cost of up to approximately $32 million.

In addition, PG&E Corporation agreed to pay any fee and expense award that the Court may grant to counsel for the plaintiffs in the San Bruno Fire Derivative Cases in an amount not to exceed $25 million for fees and $500,000 for expenses. PG&E Corporation and the Utility also agreed, under their indemnification obligations to the Individual Defendants, to pay $18.3 million of the Individual Defendants' costs, fees, and expenses incurred in connection with responding to, defending and settling the San Bruno Fire Derivative Cases and the Additional Derivative Cases, including certain fees and expenses for investigating these claims. The $18.3 million has been paid, with the majority reflected in PG&E Corporation's and the Utility's financial statements through December 31, 2016.

The settlement is expressly conditioned on, among other things, the Additional Derivative Cases being dismissed with prejudice, which condition can only be waived by PG&E Corporation and a majority of the Individual Defendants.

The preliminary settlement approval hearing took place on April 21, 2017. At this hearing, PG&E Corporation and the Utility agreed that notwithstanding the expiration of the five-year and three-year periods applicable to the corporate and gas operations therapeutics described above, neither entity will make any material changes to such therapeutics unless those changes are reported in PG&E Corporation's Corporate Responsibility and Sustainability Report or another suitable report at least three months prior to their taking effect. With this modification, the Court preliminarily approved the settlement, preliminarily finding it fair, reasonable, adequate, and in the best interests of

PG&E Corporation, the Utility, and the shareholders of PG&E Corporation.

Pursuant to the settlement, plaintiffs in the San Bruno Fire Derivative Cases filed an amended complaint on May 16, 2017 designed to capture the broadest range of claims to be dismissed as part of the overall settlement. The parties have stipulated that defendants need not respond to the amended complaint unless the settlement fails.

On July 18, 2017, the Court issued a judgment approving the settlement. The Court also directed PG&E Corporation to provide at least quarterly reports to the Court and to the City of San Bruno summarizing the progress of the implementation of the corporate governance and gas operations therapeutics. Also, as of July 19, 2017, the Additional Derivative Cases were dismissed. The settlement will become effective when all remaining conditions specified in the settlement stipulation are satisfied.

There was no impact on PG&E Corporation or the Utility's Condensed Consolidated Financial Statements for the three and six months ended June 30, 2017. PG&E Corporation estimates it will record $65 million in the period when the insurance proceeds are received.

Purchase Commitments

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. At December 31, 2016, the Utility had undiscounted future expected obligations of approximately $47 billion. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2016 Form 10-K.) The Utility has not entered into any new material commitments during the six months ended June 30, 2017.

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ITEM 2. 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 is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates, terms, and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility is also subject to the jurisdiction of other federal, state, and local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It also should be read in conjunction with the 2016 Form 10-K.

Summary of Changes in Net Income and Earnings per Share

The tables below include a summary reconciliation of the key changes in PG&E Corporation's consolidated income available for common shareholders and EPS to earnings from operations and EPS based on earnings from operations for three and six months ended June 30, 2017 as compared to the same periods in 2016 and a summary reconciliation of the key drivers of PG&E Corporation's earnings from operations and EPS based on earnings from operations for the three and six months ended June 30, 2017 as compared to the same periods in 2016. "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.

	Three Months Ended June 30,				Six Months Ended June 30,			
(in millions,	Earnings		Earnings per Common Share (Diluted)		Earnings		Earnings per Common Share (Diluted)	
except per share amounts)	2017	2016	2017	2016	2017	2016	2017	2016
PG&E Corporation's Earnings on a GAAP basis	$406	$206	$0.79	$0.41	$982	$313	$1.92	$0.63
Items Impacting Comparability: (1)								
Pipeline related expenses (2)	17	16	0.03	0.03	33	29	0.06	0.06
Legal and regulatory related expenses (3)	2	8	0.01	0.02	4	18	0.01	0.04
Fines and penalties (4)	-	112	-	0.22	36	163	0.07	0.32
Butte fire related insurance recoveries, net of legal costs (5)	(17)	(125)	(0.03)	(0.25)	(15)	101	(0.03)	0.20
GT&S revenue timing impact (6)	-	-	-	-	(88)	-	(0.17)	-
Diablo Canyon settlement-related disallowance (7)	32	-	0.06	-	32	-	0.06	-
GT&S capital disallowance	-	113	-	0.23	-	113	-	0.23
PG&E Corporation's Earnings from Operations (8)	$440	$330	$0.86	$0.66	$984	$737	$1.92	$1.48

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except as indicated below.

(1) "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.

(2) The Utility incurred costs of $29 million (before the tax impact of $12 million) and $56 million (before the tax impact of $23 million) during the three and six months ended June 30, 2017, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

(3) The Utility incurred costs of $3 million (before the tax impact of $1 million) and $7 million (before the tax impact of $3 million) during the three and six months ended June 30, 2017, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(4) The Utility incurred costs of $60 million (before the tax impact of $24 million) during the six months ended June 30, 2017, for fines and penalties. This includes costs of $32 million (before the tax impact of $13 million) during the six months ended June 30, 2017, associated with safety-related cost disallowances imposed by the CPUC in its April 9, 2015 decision ("San Bruno Penalty Decision") in the gas transmission pipeline investigations. The Utility also recorded $15 million (before the tax impact of $6 million) during the six months ended June 30, 2017, 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 recorded $12 million (before the tax impact of $5 million) and $1 million (which is not tax deductible) during the six months ended June 30, 2017, for financial remedies in connection with the settlement filed with the CPUC on March 28, 2017, related to the Order Instituting an Investigation into Compliance with Ex Parte Communication Rules. Future fines or penalties may be imposed in connection with other enforcement, regulatory, and litigation activities regarding regulatory communications.

(5) The Utility recorded insurance recoveries, net of legal costs, of $29 million (before the tax impact of $12 million) and $26 million (before the tax impact of $11 million) during the three and six months ended June 30, 2017, respectively, associated with the Butte fire. This includes $46 million (before the tax impact of $19 million) and $53 million (before the tax impact of $22 million) during the three and six months ended June 30, 2017, respectively, for insurance recoveries, partially offset by $17 million (before the tax impact of $7 million) and $27 million (before the tax impact of $11 million) recorded during the three and six months ended June 30, 2017, respectively, for legal costs associated with the Butte fire.

(6)As a result of the CPUC's final phase two decision in the 2015 GT&S rate case, during the six months ended June 30, 2017, the Utility recorded revenues of $150 million (before the tax impact of $62 million) in excess of the 2017 authorized revenue requirement, which includes the final component of under-collected revenues retroactive to January 1, 2015.

(7) As a result of the settlement agreement submitted to the CPUC in connection with the Utility's pending joint proposal to retire the Diablo Canyon Power Plant, the Utility recorded a total disallowance of $47 million (before the tax impact of $15 million) during the three and six months ended June 30, 2017, comprised of cancelled projects of $24 million (before the tax impact of $6 million) and disallowed license renewal costs of $23 million (before the tax impact of $9 million), with no corresponding charges during the same periods in 2016. A portion of the cancelled projects and disallowed license renewal costs currently is not tax deductible.

(8) "Earnings from operations" is a non-GAAP financial measure.

Reconciliation of Key Drivers of PG&E Corporation's EPS from Operations (Non-GAAP):

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	Earnings	Earnings per Common Share (Diluted)	Earnings	Earnings per Common Share (Diluted)
2016 Earnings from Operations (1)	$330	$0.66	$737	$1.48
Timing of 2015 GT&S revenue impact (2)	75	0.15	150	0.29
Growth in rate base earnings (3)	34	0.07	51	0.10
Miscellaneous	22	0.04	51	0.10
Tax benefit on stock compensation (4)	-	-	31	0.06
Impact of 2017 GRC decision (5)	(21)	(0.04)	(36)	(0.07)
Increase in shares outstanding	-	(0.02)	-	(0.04)
2017 Earnings from Operations (1)	$440	$0.86	$984	$1.92

(1) See first table above for a reconciliation of EPS on a GAAP basis to EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except for tax benefits on stock compensation. See Footnote 4 below.

(2) Represents the impact in 2016 of the delay in the Utility's 2015 GT&S rate case. The CPUC issued its final phase two decision on December 1, 2016, delaying recognition of the full 2016 revenue increase until the fourth quarter of 2016.

(3) Represents the impact of the increase in rate base as authorized in various rate cases, including the 2017 GRC, during the three and six months ended June 30, 2017 as compared to the same periods in 2016. As the final decision in the 2017 GRC was approved by the CPUC in May 2017, this amount includes revenues authorized for the three months ended March 31, 2017 that were not recorded until the second quarter of 2017.

(4) Represents the incremental tax benefit related to share-based compensation awards that vested during the six months ended June 30, 2017. Pursuant to ASU 2016-09, Compensation – Stock Compensation (Topic 718), which PG&E Corporation and the Utility adopted in 2016, excess tax benefits associated with vested awards are reflected in net income.

(5) Represents the impact of lower tax repair benefits as a result of the CPUC's final decision in the 2017 GRC proceeding, partially offset by the delayed revenue recognition of 2017 GRC-related capital costs (depreciation and interest) until the second quarter of 2017 when the CPUC issued its final decision in the 2017 GRC.

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 impact of the Butte fire, the safety culture OII and any related fines, penalties, or other ratemaking tools that could be imposed by the CPUC, including as a result of the phase two of the proceeding, the ex parte OII and the related settlement agreement that is subject to the CPUC approval, the potential recommendations that the third-party monitor may make related to the Utility's conviction in the federal criminal trial, and potential penalties in connection with the Utility's safety and other self-reports. (See Item 1A. Risk Factors in the 2016 Form 10-K.)

- The Timing and Outcome of Ratemaking Proceedings. The Utility's results may be impacted by the timing and outcome of its FERC TO18 and TO19 rate cases. (See "Transmission Owner Rate Cases" in "Regulatory Matters" below for more information.) Additionally, the Utility plans to file its 2019 GT&S rate case in the fourth quarter of 2017. 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 through 2018. (See "Disallowance of Plant Costs" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- 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. For the six months ended June 30, 2017, PG&E Corporation issued $257 million of common stock and used $190 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 $500 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 Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, changes in their respective credit ratings, general economic and market conditions, and other factors.

- Changes in the Utility Industry. The utility industry is undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California’s environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the federal approach to such matters. In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, electric vehicle infrastructure and State infrastructure modernization (e.g. rail and water projects). The Utility forecasts over $1 billion in grid investments through 2020, that would include increased remote control and sensor technology of the grid, integration investments in connection with DER bi-directional energy flows and voltage fluctuations, advanced grid data analytics, grid storage that enables renewable integration, expanded infrastructure for light, medium, and heavy-duty EVs, transmission integration for renewables, and energy efficiency and demand response programs. In addition, these changes brought about by technological advancements and climate policy may cause a reduction in natural gas usage and increase natural gas costs. The combination of reduced natural gas load and increased costs could result in higher natural gas customer bills and potential cost recovery risk.

For more information about the factors and risks that could affect 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 the 2016 Form 10-K and in Part II below under “Item 1A. Risk Factors.” In addition, this quarterly report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management’s judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management’s knowledge of facts as of the date of this report. 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

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 for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Consolidated Total	$ 406	$ 206	$ 982	$ 313
PG&E Corporation	1	1	11	3
Utility	$ 405	$ 205	$ 971	$ 310

PG&E Corporation’s net income primarily consists of income taxes and interest expense on long-term debt. The increase in PG&E Corporation’s net income for the six months ended June 30, 2017 as compared to the same period in 2016 is primarily due to the effect of income tax benefits.

Utility

The tables below show certain items from the Utility's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2017 and 2016. The tables separately identify 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)	Three Months Ended June 30, 2017 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Three Months Ended June 30, 2016 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$1,948	$ 1,376	$3,324	$1,993	$ 1,472	$3,465
Natural gas operating revenues	760	166	926	525	179	704
Total operating revenues	2,708	1,542	4,250	2,518	1,651	4,169
Cost of electricity	-	1,123	1,123	-	1,156	1,156
Cost of natural gas	-	121	121	-	75	75
Operating and maintenance	1,247	298	1,545	1,417	420	1,837
Depreciation, amortization, and decommissioning	712	-	712	700	-	700
Total operating expenses	1,959	1,542	3,501	2,117	1,651	3,768
Operating income	749	-	749	401	-	401
Interest income (1)			7			4
Interest expense (1)			(222)			(204)
Other income, net (1)			11			21
Income before income taxes			545			222
Income tax provision (1)			136			13
Net income			409			209
Preferred stock dividend requirement (1)			4			4
Income Available for Common Stock			$405			$205

(1) These items impacted earnings for the three months ended June 30, 2017 and 2016.

(in millions)	Six Months Ended June 30, 2017 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Six Months Ended June 30, 2016 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$3,930	$ 2,461	$6,391	$3,910	$ 2,687	$6,597
Natural gas operating revenues	1,539	591	2,130	1,048	499	1,547
Total operating revenues	5,469	3,052	8,521	4,958	3,186	8,144
Cost of electricity	-	1,970	1,970	-	2,106	2,106
Cost of natural gas	-	446	446	-	297	297
Operating and maintenance	2,413	636	3,049	3,065	783	3,848
Depreciation, amortization, and decommissioning	1,424	-	1,424	1,396	-	1,396
Total operating expenses	3,837	3,052	6,889	4,461	3,186	7,647
Operating income	1,632	-	1,632	497	-	497
Interest income (1)			12			8
Interest expense (1)			(438)			(405)
Other income, net (1)			28			45

Income before income taxes	1,234	145
Income tax provision (benefit) (1)	256	(172)
Net income	978	317
Preferred stock dividend requirement (1)	7	7
Income Available for Common Stock	$971	$310

(1) These items impacted earnings for the six months ended June 30, 2017 and 2016.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the three and six months ended June 30, 2017 and 2016, focusing on revenues and expenses that impacted earnings for these periods.

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Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $190 million, or 8%, and by $511 million, or 10%, in the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016 primarily due to additional base revenues authorized by the CPUC in the 2015 GT&S rate case and the 2017 GRC, and by the FERC in the TO rate case.

The final 2015 GT&S rate case decision authorized 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, beginning August 1, 2016. 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 recognized $102 million in January 2017 related to remaining retroactive revenues that had not previously been recognized.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings decreased by $170 million, or 12%, in the three months ended June 30, 2017 compared to the same period in 2016. During the three months ended June 30, 2017, the Utility recorded $291 million fewer disallowed charges (in the second quarter of 2017, the Utility incurred a $47 million disallowance related to the Diablo Canyon settlement as compared to $338 million of disallowed capital charges related to the 2015 GT&S rate case decision and San Bruno Penalty Decision during the same period in 2016) and $46 million in lower charges related to the Butte fire (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). Additionally, the Utility incurred a $24 million charge in connection with the natural gas distribution facilities record-keeping investigation during the three months ended June 30, 2016, with no similar charge in the same period of 2017. These decreases were partially offset by $214 million fewer insurance recoveries related to the Butte fire (in the three months ended June 30, 2017 the Utility recorded $46 million in insurance recoveries related to the Butte fire as compared to approximately $260 million in the same period in 2016).

The Utility's operating and maintenance expenses that impacted earnings decreased by $652 million, or 21%, in the six months ended June 30, 2017 compared to the same period in 2016. During the six months ended June 30, 2017 the Utility recorded $378 million fewer disallowed charges (in the six months ended June 30, 2017 the Utility incurred a $47 million disallowance related to the Diablo Canyon settlement as compared to $425 million of disallowed capital charges related to the 2015 GT&S rate case decision and San Bruno Penalty Decision during the same period in 2016) and $424 million in lower charges related to the Butte fire (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). Additionally, the Utility incurred a $24 million charge in connection with the natural gas distribution facilities record-keeping investigation during the six months ended June 30, 2016, with no similar charge in the same period of 2017. These decreases were partially offset by $207 million fewer insurance recoveries related to the Butte fire (in the six months ended June 30, 2017, the Utility recorded $53 million in insurance recoveries related to the Butte fire as compared to approximately $260 million in the same period in 2016).

The Utility's future financial statements will continue to be impacted by additional charges associated with costs related to the Butte fire and unrecoverable pipeline-related expenses. (See "Key Factors Affecting Financial Results" above and Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $12 million, or 2%, and by $28 million, or 2%, in the three and six months ended June 30, 2017 compared to the same periods in 2016 primarily due to higher depreciation rates as authorized in the 2017 GRC and capital additions.

Interest Expense

The Utility's interest expense for the periods presented increased by$18 million, or 9%, and by $33 million, or 8%, in the three and six months ended June 30, 2017, respectively, as compared to the same periods in 2016. These increases were primarily due to higher levels of long term debt and short term borrowings in 2017 compared to 2016.

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 income tax provision increased by $123 million in the three months ended June 30, 2017 as compared to the same period in 2016. The effective tax rates for the three months ended June 30, 2017 and 2016 were 25% and 6%, respectively. The increases in the income tax provision and the effective tax rate primarily resulted from higher pre-tax income in 2017 as compared to 2016, as well as higher benefits resulting from various property-related tax deductions recorded during the three months ended June 30, 2016 as compared to the same period in 2017.

The income tax provision increased by $428 million in the six months ended June 30, 2017 as compared to the same period in 2016. The effective tax rates for the six months ended June 30, 2017 and 2016 were 21% and (119%), respectively. The increase in the income tax provision and the effective tax rate primarily resulted from higher pre-tax income in 2017 as compared to 2016.

Utility Revenues and Costs that did not Impact Earnings

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

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Cost of purchased power	$1,079	$1,113	$1,863	$1,999
Fuel used in own generation facilities	44	43	107	107
Total cost of electricity	$1,123	$1,156	$1,970	$2,106
Average cost of purchased power per kWh (1)	$0.114	$0.099	$0.111	$0.101
Total purchased power (in millions of kWh) (2)	9,425	11,228	16,716	19,767

(1) Average cost of purchased power was impacted primarily by lower Utility electric customer demand and a larger percentage of higher cost renewable energy resources being allocated to fewer Utility electric customers.

(2) The decrease in purchased power for the three and six months ended June 30, 2017 compared to the same periods in 2016 was primarily due to lower Utility electric customer demand and an increase in generation from hydroelectric facilities.

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), regulatory requirements to procure certain types of energy, and the cost-effectiveness of each source of electricity.

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 7 of the Notes to the Condensed Consolidated Financial Statements.) 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Cost of natural gas sold	$93	$44	$386	$225
Transportation cost of natural gas sold	28	31	60	72
Total cost of natural gas	$121	$75	$446	$297
Average cost per Mcf (1) of natural gas sold	$2.27	$1.16	$2.88	$1.91
Total natural gas sold (in millions of Mcf)	41	38	134	118

(1) One thousand cubic feet

Operating and Maintenance Expenses

The Utility’s operating expenses also include certain recoverable costs that the Utility incurs as part of its operations such as pension contributions and public purpose programs costs. If the Utility were to spend over authorized amounts, these expenses could have an impact on earnings.

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 capital structure consisting of 52% equity and 48% debt and preferred stock. 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 equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue between $400 million and $500 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" 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.

Financial Resources

Debt and Equity Financings

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate gross price of up to $275 million. During the six months ended June 30, 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $28 million, net of commissions paid of $0.2 million. There were no issuances under the February 2017 EDA for the three months ended June 30, 2017. As of June 30, 2017, the remaining gross sales available under this agreement were $246 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the six months ended June 30, 2017, 4.9 million shares were issued for cash proceeds of $218 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the six months ended June 30, 2017, PG&E Corporation made equity contributions to the Utility of $190 million.

In February 2017, the Utility's $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 22, 2018. In March 2017, the Utility issued $400 million principal amount of 3.30% Senior Notes due March 15, 2027 and $200 million principal amount of 4.00% Senior Notes due December 1, 2046. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Pollution Control Bonds

In June 2017, the Utility repurchased and retired $345 million principal amount of pollution control bonds Series 2004 A through D. Additionally, in June 2017, the Utility remarketed three series of pollution control bonds, previously held in treasury, totalling $145 million in principal amount. Series 2008 F and 2010 E bear interest at 1.75% per annum and mature on November 1, 2026. Series 2008 G bears interest at 1.05% per annum and matures on December 1, 2018.

Revolving Credit Facilities and Commercial Paper Programs

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. At June 30, 2017, PG&E Corporation and the Utility had $300 million and $2.3 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements.)

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 six months ended June 30, 2017, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $60 million and $603 million, and a maximum outstanding balance of $161 million and $1.1 billion, respectively. At June 30, 2017, the Utility had an outstanding commercial paper balance of $681 million and PG&E Corporation did not have any commercial paper outstanding.

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 June 30, 2017, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 50% and 49%, 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 June 30, 2017, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In May 2017, the Board of Directors of PG&E Corporation approved a new annual common stock cash dividend of $2.12 per share ($0.53 per share quarterly), an increase from the previous annual cash dividend of $1.96 per share ($0.49 per share quarterly), and the Board of Directors of the Utility approved a new annual common stock cash dividend of $1.08 billion ($270 million quarterly), an increase from the previous annual cash dividend of $976 million ($244 million quarterly).

In May 2017, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.53 per share, totaling $271 million, of which approximately $266 million was paid on July 15, 2017, to shareholders of record on June 30, 2017.

Additionally, in May 2017, the Board of Directors of the Utility declared a common stock dividend of $270 million that was paid to PG&E Corporation on June 6, 2017 and declared dividends on its outstanding series of preferred stock, payable on August 15, 2017, to shareholders of record on July 31, 2017.

Utility Cash Flows

The Utility's cash flows were as follows:

	Six Months Ended June 30,	
(in millions)	2017	2016
Net cash provided by operating activities	$2,824	$1,803
Net cash used in investing activities	(2,489)	(2,686)
Net cash provided by (used in) financing activities	(349)	944
Net change in cash and cash equivalents	$(14)	$61

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. These items fluctuate within the normal course of business due to the timing and amount of customer billings and collections and vendor billings and payments.

During the six months ended June 30, 2017, net cash provided by operating activities increased by $1 billion compared to the same period in 2016. This increase was primarily due to additional electric and natural gas operating revenues collected as authorized by the CPUC in the 2015 GT&S rate case and by the FERC in the TO rate case and the $400 million refund to natural gas customers in the second quarter of 2016, as required by the San Bruno Penalty Decision, with no corresponding activity in 2017. Additionally, during the six months ended June 30, 2017, the Utility made payments related to the Butte fire which were mostly offset by reimbursements under its insurance policies. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

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

- the timing and outcome of ratemaking proceedings, including the TO18 and TO19 rate cases and other proceedings;

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with Butte fire and the timing and amount of related insurance recoveries, the ex parte OII, the safety culture OII, costs associated with potential recommendations by the third-party monitor, potential penalties in connection with the Utility's safety and other self-reports, and costs, fines or penalties that may be imposed in connection with other enforcement and litigation matters;

- the timing and amount of costs the Utility incurs, but does not recover, associated with its electric and natural gas systems, including amounts related to cancelled projects and relicensing;

- 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

During the six months ended June 30, 2017, net cash used in investing activities decreased by $197 million compared to the same period in 2016. The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $5.9 billion in capital expenditures in 2017, $6.1 billion in 2018 and $6.0 billion 2019.

Financing Activities

Net cash provided by financing activities decreased by $1.3 billion from $944 million for the six months ended June 30, 2016 to $349 million of net cash used in financing activities for the six months ended June 30, 2017. 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.

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 9 of the Notes to the Condensed Consolidated Financial Statements. 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. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2016 Form 10-K and "Part II. Other Information, Item 1. Legal Proceedings."

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 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

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further action is necessary to protect the federal government's business interests. On May 8, 2017, DOI sent a series of follow-up questions to the Utility seeking clarification regarding gas operational matters, the Utility's risk assessment process, and the Utility's compliance and ethics framework. The Utility expects to respond to the questions in the third quarter of 2017. The Utility could incur material costs, not recoverable through rates, to implement any remedial and other measures that could be imposed, the amount of which the Utility is currently unable to estimate.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K.

Other Pending Lawsuits

"Ghost Ship" Fire

On December 2, 2016, a fire occurred in the "Ghost Ship" warehouse in Oakland, California, during a music event. Thirty six people died in the fire, and many others were seriously injured. The families of 22 people who died in the fire have filed lawsuits against the property owner, the master tenant and neighboring tenants, and others, alleging defective electrical wiring and violations of fire safety codes.

On May 16, 2017, a master complaint was filed, and added both PG&E Corporation and the Utility as defendants. The master complaint alleges that the Utility violated the California Labor Code and various electric rules in that it (1) should have inspected the premises to evaluate potential workplace hazards to Utility employees installing/maintaining its meters there, (2) should not have permitted sub-meters in the building or should have inspected those sub-meters, and (3) should have known that the building's sub-meters and electrical system as a whole were dangerous and should have terminated service. The Utility filed a demurrer to the master complaint on June 30, 2017 on multiple grounds, including that the Utility has no duty to inspect its customers' electrical equipment. A hearing on the demurrer is scheduled for September 12, 2017.

Several investigations regarding the origin and cause of the fire were conducted, including by the City of Oakland and the County of Alameda, the CPUC, and a third-party consulting and engineering firm. In June 2017, the City of Oakland released Oakland Fire Department's report of the investigation stating that the cause of the fire was undetermined. The other investigations remain underway.

Valero Refinery Outage

On June 30, 2017, Valero Energy Corp. filed a lawsuit against the Utility after an outage occurred in its Benicia refinery in May 2017. Valero is seeking in excess of $75 million from the Utility, alleging damages to complex refinery equipment, lost revenue and other damages. The Utility has retained a third-party consulting and engineering firm to perform a causal evaluation of this outage.

PG&E Corporation and the Utility are uncertain when and how the Ghost Ship Fire and the Valero Outage 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. Significant regulatory developments that have occurred since the 2016 Form 10-K was filed with the SEC are discussed below.

2017 General Rate Case

On May 11, 2017, the CPUC issued a final decision approving the alternate PD in the Utility's 2017 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. It approved, with certain modifications, the settlement agreement that the Utility, the ORA, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016 (the "settlement agreement"). Modifications from the settlement agreement to the final decision included a tax memorandum account and approval of a stand-alone application with the CPUC or a filing in the CPUC's ongoing residential rate reform proceeding to recover customer outreach and other costs incurred as a result of residential rate reform implementation. The new tax memorandum account will track any revenue differences resulting from changes in income tax expense caused by net revenue changes, mandatory or elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes during the 2017 through 2019 GRC period. It will remain open and the balance in the account will be reviewed in every subsequent GRC proceeding until a CPUC decision closes the account.

The final decision approved a revenue requirement increase of $88 million for 2017, with additional increases of $444 million in 2018 and $361 million in 2019, in line with the amounts proposed in the settlement agreement. The following table shows the revenue requirement amounts approved in the final decision based on line of business and cost category as well as the differences between the 2016 authorized revenue requirements and the amounts approved in the final decision:

(in millions)	Amounts Approved in Final Decision (1)	Increase/ (Decrease) 2016 vs. Final Decision
Line of Business:		
Electric distribution	$4,151	$(62)
Gas distribution	1,738	(3)
Electric generation	2,115	153
Total revenue requirements	$8,004	$88
Cost Category:		
(in millions)		
Operations and maintenance	$1,794	$131
Customer services	334	15
Administrative and general	912	(99)
Less: Revenue credits	(152)	(21)
Franchise fees, taxes other than income, and other adjustments	170	132
Depreciation (including costs of asset removal), return, and income taxes	4,946	(70)
Total revenue requirements	$8,004	$88

(1) Amounts approved in the final decision are the same as the amounts that were proposed in the settlement agreement.

As required by the final decision, the Utility has submitted a variety of compliance filings, including a filing on June 12, 2017, which provides an accounting for the January 2017 $300 million expense reduction announcement and on July 10, 2017, providing an update of the cost effectiveness study for the SmartMeter™ Upgrade project. The Utility is unable to predict what, if any, actions the CPUC will take regarding these submissions.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K and 2017 Q1 Form 10-Q.

2015 Gas Transmission and Storage Rate Case

During 2016, the CPUC approved final decisions in phase one and phase two of the Utility's 2015 GT&S rate case. The phase one decision adopted 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 (2015 through 2018) and phase two determined the allocation of the $850 million penalty assessed in the San Bruno Penalty Decision and the revenue requirement reduction for the five-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding.

The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered 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. A draft of the audit report is expected in the first quarter of 2018. The decision also established various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way capital balancing accounts. 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 final phase two decision adopted 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 reduced rate base by the full amount of the disallowed capital expenditures but did not remove the associated deferred taxes, which the Utility believes constitutes a normalization violation. In the final decision, the CPUC authorized the Utility to establish a Tax Normalization Memorandum Account to track relevant costs and clarified that it is the CPUC's intention that the Utility comply with normalization rules and avoid the potential adverse consequences of a normalization violation. The CPUC allowed the Utility to seek a ruling from the IRS and the Utility filed the ruling request with the IRS on April 10, 2017.

In August 2016 and January 2017, TURN, ORA and Indicated Shippers filed applications for rehearing of the phase one and phase two decisions, respectively. The Utility cannot predict when or if the CPUC will grant the rehearings or if it will adopt the parties' recommendations. Additionally, in June 2017, the Utility filed a PFM of the phase one decision to eliminate the requirement that the Utility install new CP systems in 2018 because the Utility is not in a position to identify the optimal location for such new systems in 2018. Instead, the Utility requested to be allowed to continue its current CP program. On July 17, 2017, the CPUC directed the Utility to provide supplemental information regarding the PFM. The Utility is unable to predict if and when the CPUC would adopt the PFM. In the event the PFM is not adopted and the Utility fails to perform the mandated new CP systems, the Utility could incur fines and penalties, the amount of which the Utility is unable to predict.

With the addition of a third attrition year, the Utility's next GT&S cycle will begin in 2019. The Utility plans to file its 2019 GT&S rate case in the fourth quarter of 2017.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K and 2017 Q1 Form 10-Q.

Transmission Owner Rate Cases

Transmission Owner Rate Case for 2017

On July 29, 2016, the Utility filed a rate case (the “TO18 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 hearing, but held the hearing procedures in abeyance for settlement procedures. The order set an effective date for rates of March 1, 2017, and made the rates subject to refund following resolution of the case. On March 17, 2017, the FERC chief judge issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties. Intervenor testimonies were submitted to the CPUC on July 5, 2017. Hearings are scheduled to take place starting January 9, 2018, with an initial decision expected on or before June 1, 2018. The hearings are expected to address the prudence of the Utility’s infrastructure expansion and replacement, the Utility’s proposed return on equity of 10.9%, the Utility’s proposed increase of its composite depreciation rate from the current settlement level of 2.52% to a rate of 3.26%, and the Utility’s revised methodology for allocating existing overhead costs. The Utility is unable to predict whether the parties will be able to re-engage in settlement negotiations.

On March 31, 2017, several of the parties that had already intervened in the TO18 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the rate case. The complaint asserts that the Utility’s revenue requirement request in TO18 is unreasonably high and should be reduced. The complaint asks that, if the outcome of the litigation in TO18 is that the Utility’s revenue requirement should be set at a lower level than the settled revenue requirement from the TO17 settlement, that the FERC order refunds to that lower level determined in TO18 litigation. On April 20, 2017, the Utility answered the complaint, requesting that FERC dismiss it. The current number of commissioners at the FERC does not meet the FERC quorum requirements. Until such quorum is reached, the Utility does not expect any action to be taken on the complaint.

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Transmission Owner Rate Case for 2018

On July 27, 2017, the Utility filed a rate case (the "TO19 rate case") at the FERC requesting a 2018 retail electric transmission revenue requirement of $1.792 billion, a $74 million increase over the proposed 2017 revenue requirement of $1.718 billion. A FERC order accepting the TO19 rate case filing, setting an effective date for rates, subject to hearing and refund, is expected by September 30, 2017. While the Utility requested that the new rates be effective on October 1, 2017, subject to refund, pending a final decision by the FERC, the Utility anticipates that the rates will be suspended for five months and made effective on March 1, 2018, subject to refund.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K and 2017 Q1 Form 10-Q.

Cost of Capital

On July 13, 2017, the CPUC voted out a final decision in the cost of capital proceeding for the Utility, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company (collectively, the "IOUs"). The CPUC adopted, with no modifications, the revised proposed decision issued by the two assigned Administrative Law Judges on July 12, 2017, granting in full the joint PFM that the IOUs, the ORA, and TURN submitted to the CPUC on February 7, 2017.

As requested in the PFM, the final decision extends the Utility's next cost of capital application filing deadline by two years to April 22, 2019, for the year 2020. The final decision also reduces the Utility's authorized return on equity from 10.40% to 10.25%, effective January 1, 2018, and resets the Utility's authorized cost of long-term debt and preferred stock effective 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.) In addition, the decision suspends the cost of capital adjustment mechanism to adjust cost of capital for 2018, but allows the adjustment mechanism to operate for 2019 if triggered. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity remains unchanged.

The final decision also leaves the proceeding open to facilitate gathering of information to inform the next cost of capital proceeding, as well as to provide a possible venue in which to consider whether the Utility's return on equity should be reduced until any recommendations that the CPUC may adopt in the second phase of its safety culture investigation are implemented, as described in the assigned Commissioner's May 8, 2017 Scoping Memo and Ruling issued in the Safety Culture OII.

The Utility expects to submit to the CPUC in September 2017 its updated cost of capital and corresponding revenue requirement impacts resulting from the adopted PFM with an effective date of January 1, 2018. While the actual changes to the Utility's revenue requirement will not be known until the above-mentioned filing is submitted and the actual cost of debt through August 2017 and the forecasted cost through 2018 are quantified in the third quarter of 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.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K and 2017 Q1 Form 10-Q.

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. PG&E subsequently modified its testimony to move consideration of two tranches of post-2025 replacement procurement to the CPUC's Integrated Resource Plan proceeding.

More than 40 parties have submitted responses and protests to the Utility's application. Rebuttal testimony and comments on the community impact mitigation program settlement agreement were submitted to the CPUC on March 17, 2017. Evidentiary hearings took place in April 2017. Certain intervenors argued that a portion of or the entire community impact mitigation program and employee retention plan be funded by shareholders.

On May 23, 2017, the Utility filed a settlement agreement that was reached with the parties listed above as well as TURN, ORA, and San Luis Obispo Mothers for Peace, related to the recovery of license renewal costs and cancelled project costs. The settlement agreement would allow for recovery from customers of $18.6 million of the total license renewal project cost of $53 million evenly over an 8-year period beginning January 1, 2018. Related to cancelled project costs, the settlement agreement would allow for recovery from customers of 100% of the direct costs incurred prior to June 30, 2016, and 25% recovery of direct costs incurred after June 30, 2016. On June 22, 2017, the Green Power Institute filed comments on the settlement agreement recommending that only $9.3 million of the license renewal project costs be recovered from customers. During the three and six months ended June 30, 2017, the Utility incurred charges of $47 million related to the settlement agreement, of which $24 million is for cancelled projects and $23 million is for disallowed license renewal costs.

Opening and reply briefs were filed on May 26, 2017, and June 16, 2017, respectively, in which no new issues were raised. 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 60 years. On August 28, 2016, the World Business Academy filed a writ in the Los Angeles Superior Court asserting 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 alleging that the State Lands Commission should be required to perform an environmental review of the new lands lease. The trial took place on July 11, 2017, in Los Angeles Superior Court and the judge dismissed the petition on all grounds, ruling that the State Lands Commission properly determined the short term lease extension was subject to the existing facilities exemption under the California Environmental Quality Act. World Business Academy has 60 days from entry of judgement to appeal the decision to the California Court of Appeals.

Asset Retirement Obligations

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. On May 25, 2017, the CPUC issued a final decision in the 2015 NDCTP adopting a nuclear decommissioning cost estimate of $1.1 billion for Humboldt Bay, corresponding to the Utility's request, and

$2.4 billion for Diablo Canyon, compared to the Utility's request of $3.8 billion, or 64 percent of its request. On an aggregate basis, the final decision adopted a $3.5 billion total nuclear decommissioning cost estimate, compared to $4.8 billion requested by the Utility. Compared to the Utility's estimated cost to decommission Diablo Canyon, the final decision adopts assumptions which lower costs for large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility can seek recovery of these costs in the 2018 NDCTP. The CPUC's final decision resulted in a $66 million reduction to the ARO on the Condensed Consolidated Balance Sheets related to the assumed length of the wet cooling period of spent nuclear fuel after plant shut-down.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.4 billion at June 30, 2017, and $3.5 billion at December 31, 2016. 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 June 30, 2017, the nuclear decommissioning trust accounts' total fair value was $3.1 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.

The Utility expects to file its 2018 NDCTP application in late 2018 or early 2019.

For more information, see PG&E Corporation's and the Utility's 2016 Form 10-K and 2017 Q1 Form 10-Q.

Application to Establish a Wildfire Expense Memorandum Account

On July 26, 2017, the Utility filed an application with the CPUC requesting to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date. Concurrently with this application, the Utility also submitted a motion to the CPUC requesting that the WEMA be deemed effective as of July 26, 2017, such that the Utility may begin recording costs to the account, while the application is pending before the CPUC.

Under the WEMA as proposed, the Utility would record incremental costs related to wildfire, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been authorized in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, would be credited to the WEMA as they are received. Any recovery in rates of costs recorded to the WEMA is specifically conditioned on authorization by a CPUC decision that may be issued in response to a future application by the Utility.

The Utility intends to begin recording Butte fire costs to the WEMA upon its implementation. The WEMA would not include costs related to the restoration of service and repair of utility facilities resulting from the Butte fire. The Utility already has cost recovery mechanisms approved by the CPUC, the Major Emergency Balancing Account and Catastrophic Events Memorandum Account for recording and addressing recovery of costs related to restoration of service and repair of utility facilities, which are different from those intended to be tracked in the WEMA. Any costs recoverable through the Major Emergency Balancing Account and Catastrophic Events Memorandum Account will be excluded from the WEMA.

Under the schedule proposed by the Utility, a proposed decision on the application could be issued as early as in October 2017. The Utility is unable to predict if the CPUC will approve its application. As indicated in Note 9 of the Notes to the Condensed Consolidated Financial Statements, if the Utility's ultimate liability in connection with the Butte fire litigation were to exceed the amounts recoverable under its liability insurance coverage and from third parties, the Utility would expect to seek autorization from the CPUC to recover any excess amounts from customers.

Portfolio Allocation Methodology Filing and Power Charge Indifference Adjustment OIR

On April 25, 2017, the Utility, along with Southern California Edison Company and San Diego Gas & Electric Company, filed a joint application with the CPUC on how to allocate costs associated with long-term power contracts in a manner that ensures all customers are treated equally. At issue is how customers within communities that choose to implement CCA power arrangements and those served under direct access pay for their share of the contract costs.

The utilities believe that these customers are not paying their full share of costs associated with the long-term contracts, which results in other customers paying more, which is inconsistent with state law. The Utility is committed to helping create a cost allocation method that treats all customers fairly and equally, whether they continue to receive service from the Utility or choose a CCA or direct access provider. The Utility projects that approximately 50 percent of its customers will purchase electricity from a CCA or direct access provider by 2020. Without changes to the current cost allocation system, contract and facilities costs will be shifted to customers who remain with the Utility or live in areas that do not have access to alternative electricity providers. The utilities' joint proposed approach would replace the current system, which is known as the PCIA, with an updated system known as the Portfolio Allocation Methodology.

On June 29, 2017, the CPUC dismissed the Utility's joint Portfolio Allocation Methodology application without prejudice and approved instead an OIR to review, revise, and consider alternatives to the PCIA. Topics to be included in the OIR are as follows: (1) improve the transparency of the existing PCIA process, (2) revise the current PCIA methodology to increase stability and certainty, (3) review specific issues related to inputs and calculations for the current PCIA methodology, and (4) consider alternatives to the PCIA. The OIR indicates that although this rulemaking focuses on the PCIA, it is situated in the larger context of consumer choice in energy services. However, it is not intended to be a follow-up to the CPUC and Energy Commission Joint En Banc on Retail Choice in California, that will be separately developed by the CPUC. Comments on the OIR are due and a preliminary scoping memo is expected on July 31, 2017. The Utility expects a final decision within 18 months of the opening of the rulemaking.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed DRP 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.

On February 27, 2017, the CPUC issued a ruling that seeks the development of a process for incorporating DER forecasts into the DRP and takes into consideration the coordination with other statewide planning and forecasting processes, such as the CPUC's Integrated Resource Plan process, the CEC's Integrated Energy Policy Report, and the CAISO's Transmission Planning Process. This ruling mandated the Utility, along with Southern California Edison and San Diego Gas and Electric to develop a draft joint proposal for the CPUC and stakeholder consideration on the process for developing DER forecasts that is coordinated with the various statewide planning and forecasting processes. The utilities submitted a draft joint proposal for CPUC and stakeholder consideration on June 9, 2017. Comments were submitted by stakeholders on the draft proposal on July 10, 2017 and a CPUC decision on the proposal may be issued before the end of 2017.

On May 16, 2017, the CPUC issued a ruling requiring stakeholder responses to questions posed in a CPUC staff white paper on grid modernization. The white paper is aimed at informing the development of a CPUC framework to evaluate grid-modernization investments. A workshop took place and comments were submitted by stakeholders in June 2017. The CPUC may issue a decision on a grid-modernization investment framework by the end of 2017.

On June 15, 2017, the CPUC authorized the Utility's second DRP demonstration project to test and evaluate the ability of DERs to achieve locational benefits. On June 30, 2017, the CPUC issued another ruling soliciting stakeholder responses on questions set forth in a CPUC staff white paper on proposing a DIDF. The DIDF aims to establish a future process for identifying distribution deferral opportunities for DERs. Stakeholder comments on DIDF are due on August 7, 2017, with reply comments due August 18, 2017. The CPUC may issue a decision on a DIDF framework and a future process for development of DER growth forecasts by the end of 2017. The Utility is unable to predict when a final CPUC decision approving, disapproving, or modifying the Utility's DRP will be issued.

Integrated Distributed Energy Resources Proceeding – Regulatory Incentives Pilot Program

On April 4, 2016, the CPUC 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 stated that it did not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities. 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.

In June 2017, the Utility submitted a pilot project proposal to the CPUC for approval to begin solicitations. The pilot aims to evaluate the effectiveness of an earnings opportunity in motivating utilities to source DERs. A CPUC decision approving, disapproving, or modifying the pilot project is expected by the end of 2017.

Transportation Electrification Application

California Law (SB 350) requires the CPUC, in consultation with the CARB and the CEC, to direct the Utility and electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the Utility and the other large IOUs to file TE applications which include both short-term projects (of up to $20 million in total) and two to five-year programs with a requested revenue requirement determined by the Utility. On 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 vehicle sectors. The CPUC has scheduled proposed decisions to be issued on the Utility's TE application by the end of 2017.

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.

On February 21, 2017, California State Senator Jerry Hill filed a petition for modification of the CPUC's September 29, 2016 decision regarding the safety citation program. The petition for modification requests that the decision be modified to reinstate mandatory self-reporting for gas safety potential violations and require gas utilities to notify local governments within 30 days when a self-report is submitted to SED. Under the request, electric utilities would keep the voluntary self-reporting regime and would not be required to notify local governments, but the CPUC has discretion to direct notification within ten days on a case-by-case basis. The CPUC's Office of Safety Advocates filed a response suggesting additional potential modification to the gas and electric safety citation programs. The Utility cannot predict when or how the CPUC will act on the petition of modification.

Bulk Electric System Reliability Standard Violations

The FERC has certified the NERC as the Electric Reliability Organization with the authority to establish and enforce reliability standards for the bulk electric system, subject to the FERC review. The NERC has delegated authority to the WECC as the Regional Entity for the Western Interconnection to monitor compliance with reliability standards, assure mitigation of violations, and assess penalties, subject to the NERC and the FERC review. The NERC's reliability standards govern all aspects of the operation of the grid that impact reliability, including protection of critical assets, cybersecurity, communications, emergency preparedness, vegetation management, transmission planning, transmission operation, facilities design and rating.

The WECC, NERC, and FERC periodically audit electric utilities for compliance with the reliability standards, and may also conduct spot checks and investigate potential compliance violations. The WECC, NERC, and FERC have the authority to impose monetary and non-monetary sanctions for violations of reliability standards, including monetary penalties up to $1 million per day per violation. The amount of a penalty depends upon the risk posed by the violation of a particular standard, the severity of the particular violation, and the duration of the violation. Entities found in violation of a standard must also submit a mitigation plan for approval by the WECC, NERC, and FERC. Entities generally discuss with the WECC the sanctions for an alleged violation and may mutually agree on a reduction in a proposed penalty depending upon mitigating factors and mitigation plans.

The Utility has submitted several self-reports to the WECC that are pending the WECC's review. Previously, final monetary penalties that were imposed on the Utility for alleged violations of reliability standards have ranged from less than a few thousand dollars to $1.2 million.

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Natural Gas Storage Regulations

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. 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. The DOGGR released proposed regulations on May 19, 2017 that would replace the emergency regulations issued in 2016. The proposed regulations maintain the major elements from the 2016 emergency regulations but are more prescriptive and include some new requirements for records management, leak reporting, and decommissioning. Public workshops took place and comments were submitted to the DOGGR regarding the proposed regulations in July 2017. The Utility is unable to estimate the timing of when the DOGGR will make changes and/or adopt the proposed regulations.

The PHMSA has also issued interim final rules effective January 18, 2017 regulating gas storage facilities at the federal level. PHMSA's regulations are subject to a challenge in federal courts related to the implementation timeframe and the practices that have become mandatory under these new regulations. PG&E Corporation and the Utility are unable to predict the outcome of that challenge.

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 various risk factors. On March 20, 2017, the Utility submitted an advice letter with the CPUC to request a memorandum account to track the future incremental costs associated with implementing the new regulations. On July 6, 2017, the CPUC rejected the advice letter stating that it includes matters that require deliberation beyond the scope of an advice letter.

CPUC General Order 112-F

In June 2015, the CPUC issued a decision that imposed new operation and maintenance standards for natural gas systems. The new standards became effective January 1, 2017. The new standards require additional expenditures in the areas of gas leak repair, leak survey, high consequence area identification, and operator qualifications, and could impact the Utility's ability to timely recover certain costs. The Utility expects to incur over $50 million in costs to implement the new standards in 2017 and 2018, cumulatively. On January 31, 2017, the Utility filed a petition for modification of the CPUC's 2015 decision requesting a memorandum account to record for possible future recovery the cost to implement the new requirements concerning the Utility's natural gas transmission operations in 2017 and 2018. (In June 2016, the CPUC modified the GT&S rate case cycle, making the earliest effective date for rates for the next GT&S rate case January 1, 2019, rather than 2018. As a result, in absence of the requested memorandum account, the Utility would not be able to recover additional revenue to pay for costs incurred prior to 2019.) The Utility is unable to predict the timing and outcome of this proceeding.

Retail Choice

On May 19, 2017, California energy companies, along with other stakeholders discussed retail choice and the future of California's electric industry at a CPUC "en banc" meeting. Specifically, the goal of the meeting was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future. The CPUC has indicated that it intends to open a rulemaking to examine, and coordinate among other open proceedings, rate design and the future role, structure, and other functions of the three California electric IOUs. The Utility is unable to predict when the CPUC may open a rulemaking.

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STATE AND FEDERAL INITIATIVES

California Cap-and-Trade Program Extension

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. To achieve the 2020 target, CARB has approved a comprehensive Cap-and-Trade Program that sets gradually declining limits on the amount of GHGs that may be emitted by major GHG emission sources. On June 28, 2017, the California Supreme Court denied an appeal from lower courts brought by business groups opposing the Cap-and-Trade Program. On July 17, 2017, the California legislature approved two bills supported by the California Governor and legislative leaders, AB 398 and AB 617. AB 398 will extend the Cap-and-Trade Program from 2020 to 2030 and AB 617 will improve California air quality control through increased monitoring and penalties. CARB's 2017 Scoping Plan Update establishes the framework to meet the new climate targets and is expected to be adopted by the end of 2017.

Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure Executive Order

On May 11, 2017, President Donald J. Trump signed Executive Order "Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure" that includes provisions, among other things, for the executive branch to use its authorities and capabilities to support the cybersecurity risk management efforts of the owners and operators of critical infrastructure. Among other things, it requires heads of appropriate sector-specific agencies to identify authorities and capabilities that agencies could employ to support the cybersecurity efforts of critical infrastructure entities identified to be at greatest risk of attacks that could reasonably result in catastrophic regional or national effects on public health or safety, economic security, or national security. It also requires within 180 days of the cybersecurity order, before November 7, 2017, a classified report detailing the findings and recommendations for better supporting the cybersecurity risk management efforts of such entities. The Utility is unable to predict the impact that the executive order will have on the Utility until the report is released and the federal administration takes steps to implement some or all of the report's recommendations.

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 CO_2 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 Note 9 of the Notes to the Condensed Consolidated Financial Statements, as well as "Item 1A. Risk Factors" and Note 13 of the Notes to the Consolidated Financial Statements in the 2016 Form 10-K.)

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CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (See "Purchase Commitments" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Commitments in the 2016 Form 10-K.

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 in the 2016 Form 10-K (the Utility's commodity purchase agreements).

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage, emissions allowances and offset credits, other goods and services, and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "commodity price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

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 risk mitigation purposes 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. 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. These activities are discussed in detail in the 2016 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the six months ended June 30, 2017.

CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed 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 Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, accounting policies for insurance recoveries, AROs, and pension and other postretirement benefits plans to be critical accounting policies. These policies are considered 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. These accounting policies and their key characteristics are discussed in detail in the 2016 Form 10-K.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 2 of the Notes to the Condensed 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 report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "antic "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the TO18 and TO19 rate cases and other ratemaking and regulatory proceedings;

- the timing and outcome of the Butte fire litigation, whether insurance is sufficient to cover the Utility's liability resulting therefrom; the timing and outcome of any proceeding to recover costs in excess of insurance from customers, if any; the effect, if any, that the SED's $8.3 million citations issued in connection with the Butte fire may have on Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;

- the outcome of the probation and the monitorship imposed as a result of the Utility's conviction in the federal criminal trial, the timing and outcomes of the debarment 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- and electric- related laws and regulations and ex parte communications, 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 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, and the timing and outcome of the federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act;

- the effects on PG&E Corporation and the Utility's 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;

- whether the Utility is able to successfully adapt its business model to significant change that the electric industry is undergoing and the impact such change will have on the natural gas industry;

- the impact of the increasing cost of natural gas regulations, including 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, the PHSMA rules effective January 18, 2017 regulating gas storage facilities at the federal level; and the CPUC General Order 112-F that went into effect on January 1, 2017 and that requires additional expenditures in the areas of gas leak repair, leak survey, high consequences area identification, and operator qualifications, and could impact the Utility's ability to timely recover such costs;

- whether the Utility and its third-party vendors and contractors are able to protect the Utility's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;

- the timing and outcome of the complaint filed by the CPUC and certain other parties with the FERC on February 2, 2017 that requests that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO's Transmission Planning Process in order to allow for participation and input from interested parties;

- 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 safety culture OII, including of its phase two proceeding opened on May 8, 2017 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 outcome of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cyber security, environmental laws and regulations;

- the outcomes of the CPUC's data requests, including in connection with the Utility's SmartMeter™ cost-benefit analysis, and of the Utility's PFMs, including in connection with the installation of new CP systems in 2018;

- the timing and outcomes of the "Ghost Ship" and Valero refinery outage lawsuits;

- 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 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; 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;

- the impact of droughts, floods, 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), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility’s service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and of the potential inadequacy of the Utility’s emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility’s insurance coverage is available for these types of claims and sufficient to cover the Utility’s liability;

- the breakdown or failure of equipment that can cause fires and unplanned outages (such as the power outage on April 21, 2017 in San Francisco, that initial information suggests was due to an equipment failure that led to a fire at Larkin Street substation, and that impacted approximately 88,000 customers); and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;

- 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;

- 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 PG&E's procurement service for CCAs;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- whether, as a result of Westinghouse's Chapter 11 proceeding, the Utility will experience issues with nuclear fuel supply, nuclear fuel inventory, and related services and products that Westinghouse supplies, and whether such proceeding will affect the Utility's contracts with Westinghouse;

- 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 Utility's conviction in the federal criminal trial, and other enforcement matters will impact 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.

Additional information about risks and uncertainties, including more detail about the factors described in this report, is included throughout MD&A, in "Item 1A. Risk Factors" below, and in the 2016 Form 10-K, including the "Risk Factors" section. Forward-looking statements speak only as of the date they are made. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.)

ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of June 30, 2017, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended June 30, 2017, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statements and Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, "Enforcement and Litigation 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.

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 June 30, 2017, approximately 60 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 2,050 individual plaintiffs representing approximately 1,180 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. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may increase in the future. The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, among other claims.

Also, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

Two trials have been scheduled in connection with the Butte fire. On April 14, 2017, the Superior Court of California for Sacramento County found that six “preference” households (households that include individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling) are entitled to a trial. The trial has been scheduled to commence on August 14, 2017 in Sacramento.

The court also set a representative trial date for October 30, 2017 in Sacramento. A representative trial is a trial where the parties agree, or the court decides, on plaintiffs who are “representative” of broader groups of plaintiffs such that the trial may assist the parties in settling other cases after obtaining verdicts in the representative trial.

For more information regarding the Butte fire, see Note 9 “Contingencies and Commitments” of the Notes to the Condensed Consolidated Financial Statements.

Federal Criminal Trial

As previously disclosed, 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, subsequently reduced to 11 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 August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on 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 which was paid to the federal government in February 2017, certain advertising requirements, and community service. The Utility did not appeal the convictions. The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period.

PG&E Corporation and the monitor entered into a monitor retention agreement on April 12, 2017. The goal of the monitorship is 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 is 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.

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 costs resulting from potential recommendations that the monitor may make in the future).

Litigation Related to the San Bruno Accident

As of June 30, 2017, there were seven shareholder derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by certain current and former officers and directors (the “Individual Defendants”), among other claims. Four of the cases were consolidated as the San Bruno Fire

Derivative Cases and are pending in the Superior Court of California, County of San Mateo (the "Court"). 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. (the "Additional Derivative Cases").

On March 15, 2017, the parties in the San Bruno Fire Derivative Cases filed with the Court a settlement that they reached to resolve the consolidated shareholder derivative lawsuit and certain additional claims against the Individual Defendants. Pursuant to the settlement stipulation, subject to certain conditions: (1) the Individual Defendants' directors and officers liability insurance carriers will pay $90 million to PG&E Corporation within 11 business days of the entry of the judgment approving settlement in the San Bruno Fire Derivative Cases, (2) PG&E Corporation and the Utility will implement certain corporate governance therapeutics for five years, and (3) the Utility will implement certain gas operations therapeutics and maintain certain of them for three years, at an estimated cost of up to approximately $32 million.

In addition, PG&E Corporation agreed to pay any fee and expense award that the Court may grant to counsel for the plaintiffs in the San Bruno Fire Derivative Cases in an amount not to exceed $25 million for fees and $500,000 for expenses. PG&E Corporation and the Utility also agreed, under their indemnification obligations to the Individual Defendants, to pay $18.3 million of the Individual Defendants' costs, fees, and expenses incurred in connection with responding to, defending and settling the San Bruno Fire Derivative Cases and the Additional Derivative Cases, including certain fees and expenses for investigating these claims. The $18.3 million has been paid, with the majority reflected in PG&E Corporation's and the Utility's financial statements through December 31, 2016.

The settlement is expressly conditioned on, among other things, the Additional Derivative Cases being dismissed with prejudice, which condition can only be waived by PG&E Corporation and a majority of the Individual Defendants.

The preliminary settlement approval hearing took place on April 21, 2017. At this hearing, PG&E Corporation and the Utility agreed that notwithstanding the expiration of the five-year and three-year periods applicable to the corporate and gas operations therapeutics described above, neither entity will make any material changes to such therapeutics unless those changes are reported in PG&E Corporation's Corporate Responsibility and Sustainability Report or another suitable report at least three months prior to their taking effect. With this modification, the Court preliminarily approved the settlement, preliminarily finding it fair, reasonable, adequate, and in the best interests of PG&E Corporation, the Utility, and the shareholders of PG&E Corporation.

On July 18, 2017, the Court issued a judgment approving the settlement. The Court also directed PG&E Corporation to provide at least quarterly reports to the Court and to the City of San Bruno summarizing the progress of the implementation of the corporate governance and gas operations therapeutics. Also, as of July 19, 2017, the Additional Derivative Cases were dismissed. The settlement will become effective when all remaining conditions specified in the settlement stipulation are satisfied.

For additional information regarding these matters, see "Part I, Item 3. Legal Proceedings" in the 2016 Form 10-K and Note 9.

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 non-compliance with electric and natural gas safety regulations and other enforcement matters. See the discussion entitled "Enforcement and Litigation Matters" above in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2016 Form 10-K.

Diablo Canyon Nuclear Power Plant

For more information regarding the 2003 settlement agreement between the Central Coast Water Board, the Utility, and the California Attorney General's Office, see "Part I, Item 3. Legal Proceedings" in the 2016 Form 10-K.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation’s and the Utility’s future financial condition, results of operations, and cash flows, see the section of the 2016 Form 10-K entitled “Risk Factors,” as supplemented below, and the section of this quarterly report entitled “Cautionary Language Forward-Looking Statements.”

The electric power industry is undergoing significant change driven by technological advancements and a decarbonized economy, which could materially impact the Utility’s operations, financial condition, and results of operations.

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and a decarbonized economy. California's environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the federal approach to such matters. California utilities are experiencing increasing deployment by customers and third parties of DERs, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. This growth will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect DERs.

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

To this end, the CPUC is conducting proceedings to: evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of DERs; consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by DERs, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator. The CPUC has also recently opened proceedings regarding the creation of a shared database or statewide census of utility poles and conduits in California and increased access by communications providers to utility rights-of-way. This proceeding could require utilities to invest significant resources into inspecting poles and conduits, limit available capacity in existing rights-of-way, or impose other requirements on utilities facilities. The Utility is unable to predict the outcome of these proceedings.

In addition, the CPUC has recently opened discussions on liberalizing California's retail electricity market. On May 19, 2017, California energy companies, along with other stakeholders discussed retail choice and the future of the state's electricity industry at a CPUC "en banc" meeting. Specifically, the goal of the "en banc" was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future. The CPUC has indicated that it intends to open a rulemaking to examine, and coordinate among other open proceedings, rate design and the future role, structure, and other functions of the three California electric IOUs.

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

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

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

A cyber incident, cyber security breach or physical attack on the Utility's operational networks and information technology systems could have a material effect on its business and results of operations.

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

The Utility also relies on complex information technology systems that allow it to create, collect, use, disclose, store and otherwise process sensitive information, including the Utility's financial information, customer energy usage and billing information, and personal information regarding customers, employees and their dependents, contractors, and other individuals. In addition, the Utility often relies on third-party vendors to host, maintain, modify, and update its systems and these third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience security incidents. Any incidents or disruptions in the Utility's information technology systems could impact our ability to track or collect revenues and to maintain effective internal controls over financial reporting.

The Utility and its third party vendors have been subject to, and will likely continue to be subject to 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 operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, 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 maintains cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

The Utility purchases its nuclear fuel assemblies from a sole source, Westinghouse. If Westinghouse experiences business disruptions as a result of Chapter 11 proceedings, the Utility could experience disruptions in nuclear fuel supply, delays in connection with its Diablo Canyon outages and refuelings, and rejection in bankruptcy of its contracts with Westinghouse.

The Utility purchases its nuclear fuel assemblies for Diablo Canyon from a sole source, Westinghouse. The Utility also stores nuclear fuel inventory at the Westinghouse fuel fabrication facility. In addition, Westinghouse provides the Utility with Diablo Canyon outage support services, nuclear fuel analysis, OEM engineering and parts support. On March 29, 2017, Westinghouse filed for Chapter 11 protection in the United States Bankruptcy Court, Southern District of New York. In the event that Westinghouse experiences business disruptions in its nuclear fuel business as a result of bankruptcy proceedings or otherwise, the Utility could experience issues with its nuclear fuel supply and delays in connection with Diablo Canyon refueling outages. The Utility also could experience losses in connection with its nuclear fuel inventory and Westinghouse could seek to reject in bankruptcy its contracts with the Utility. Diablo Canyon's Unit 2 refueling outage is expected to occur in the first quarter of 2018. If Westinghouse were to reject the Utility's contracts or fail to deliver nuclear fuel or provide outage support to the Utility, the Utility's operation of Diablo Canyon would be adversely affected. PG&E Corporation and the Utility also could experience additional costs, including decreased electricity market revenues, in the event that one or both Diablo Canyon units are unable to operate. There can be no assurance that any such additional costs would be recoverable in the rates the Utility is permitted to recover from its customers. Furthermore, the Utility currently is not able to estimate the nature or amount of additional costs and expenses that it might incur in connection with the uncertainties surrounding Westinghouse but such costs and expenses could be material.

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

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

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended June 30, 2017, PG&E Corporation made equity contributions totaling $65 million to the Utility in order to maintain the 52% common equity component of the Utility's CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended June 30, 2017.

Issuer Purchases of Equity Securities

During the quarter ended June 30, 2017, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. During the quarter ended June 30, 2017, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

The Utility's earnings to fixed charges ratio for the six months ended June 30, 2017 was 2.92. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2017 was 2.89. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement No. 333-215427.

PG&E Corporation's earnings to fixed charges ratio for the six months ended June 30, 2017 was 2.87. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-215425.

ITEM 6. EXHIBITS

*10.1	Form of Restricted Stock Unit Agreement for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.2	Form of Performance Share Agreement subject to financial goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.3	Form of Performance Share Agreement subject to safety and affordability goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.4	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.5	Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.6	Performance Share Agreement subject to safety and affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.7	Form of Restricted Stock Unit Agreement for 2017 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.8	Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for non-annual award under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.9	Separation Agreement between Pacific Gas and Electric Company and Desmond Bell dated January 6, 2017 and amended as of April 25, 2017
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
31.1	Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
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101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

*Management contract or compensatory agreement.

**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

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**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

/s/ JASON P. WELLS
Jason P. Wells
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ DAVID S. THOMASON
David S. Thomason

Vice President, Chief Financial Officer and Controller

(duly authorized officer and principal financial officer)

Dated: July 27, 2017