PG&E Corp
Form 10-Q
November 05, 2018

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 September 30, 2018
	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 77 Beale Street P.O. Box 770000 San Francisco, California 94177	Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California

		94177
	Address of principal executive offices, including zip code	
PG&E Corporation (415) 973-1000		Pacific Gas and Electric Company (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 every Interactive Data File required to be submitted 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 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	
	[ ] Smaller reporting company	[ ] Emerging growth company
Pacific Gas and Electric Company:	[ ] Large accelerated filer	[ ] Accelerated filer
	[X] Non-accelerated filer	
	[ ] 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
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 October 25, 2018:	
PG&E Corporation:	518,674,276
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 SEPTEMBER 30, 2018

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GLOSSARY

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

2017 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, 2017
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
Cal PA	Public Advocates Office of the California Public Utilities Commission (formerly known as Office of Ratepayer Advocates or ORA)
CCA	Community Choice Aggregator
CEC	California Energy Resources Conservation and Development Commission
CEMA	Catastrophic Event Memorandum Account
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DER	distributed energy resources
Diablo Canyon	Diablo Canyon nuclear power plant
DOGGR	Division of Oil, Gas, and Geothermal Resources of the California Department of Conservation
DTSC	Department of Toxic Substances Control
EPS	earnings per common share
EV	electric vehicle
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FHPMA	fire hazard prevention memorandum account
GAAP	U.S. Generally Accepted Accounting Principles
GHG	greenhouse gas
GRC	general rate case
GT&S	gas transmission and storage
HSM	hazardous substance memorandum account
IOU(s)	investor-owned utility(ies)
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations set forth in Item 2 of this Form 10-Q
MGP(s)	manufactured gas plants
NAV	net asset value
NDCTP	Nuclear Decommissioning Cost Triennial Proceedings
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
OES	State of California Office of Emergency Services
OII	order instituting investigation
OIR	order instituting rulemaking
PCIA	Power Charge Indifference Adjustment
PD	proposed decision
PFM	petition for modification
RAMP	Risk Assessment Mitigation Phase
ROE	return on equity
SB	Senate Bill

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SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
Tax Act	Tax Cuts and Jobs Act of 2017
TE	transportation electrification
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)
WEMA	Wildfire Expense Memorandum Account

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited) Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2018	2017	2018	2017
Operating Revenues				
Electric	$3,466	$3,648	$9,729	$10,036
Natural gas	915	869	2,942	2,999
Total operating revenues	4,381	4,517	12,671	13,035
Operating Expenses				
Cost of electricity	1,256	1,466	3,038	3,436
Cost of natural gas	69	78	437	524
Operating and maintenance	1,611	1,324	5,001	4,453
Wildfire-related claims, net of insurance recoveries	(10)	53	2,108	—
Depreciation, amortization, and decommissioning	759	710	2,257	2,134
Total operating expenses	3,685	3,631	12,841	10,547
Operating Income (Loss)	696	886	(170)	2,488
Interest income	14	9	35	22
Interest expense	(232)	(220)	(678)	(663)
Other income, net	104	38	318	98
Income (Loss) Before Income Taxes	582	713	(495)	1,945
Income tax provision (benefit)	15	160	(527)	403
Net Income	567	553	32	1,542
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$564	$550	$22	$1,532
Weighted Average Common Shares Outstanding, Basic	517	513	516	511
Weighted Average Common Shares Outstanding, Diluted	517	516	517	514
Net Earnings Per Common Share, Basic	$1.09	$1.07	$0.04	$3.00
Net Earnings Per Common Share, Diluted	$1.09	$1.07	$0.04	$2.98

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Net Income	$567	$553	$32	$1,542
Other Comprehensive Income				
Pension and other post-retirement benefit plans obligations (net of taxes of $0, $0, $0, and $0, at respective dates)	1	—	1	1
Total other comprehensive income	1	—	1	1
Comprehensive Income	568	553	33	1,543
Preferred stock dividend requirement of subsidiary	3	3	10	10
Comprehensive Income Attributable to Common Shareholders	$565	$550	$23	$1,533

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited) Balance At September 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$430	$ 449
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $58 and $64 at respective dates)	1,297	1,243
Accrued unbilled revenue	962	946
Regulatory balancing accounts	1,326	1,222
Other	902	861
Regulatory assets	229	615
Inventories:		
Gas stored underground and fuel oil	116	115
Materials and supplies	389	366
Other	698	464
Total current assets	6,349	6,281
Property, Plant, and Equipment		
Electric	56,860	55,133
Gas	20,798	19,641
Construction work in progress	2,855	2,471
Other	2	3
Total property, plant, and equipment	80,515	77,248
Accumulated depreciation	(24,310)	(23,459)
Net property, plant, and equipment	56,205	53,789
Other Noncurrent Assets		
Regulatory assets	4,429	3,793
Nuclear decommissioning trusts	2,917	2,863
Income taxes receivable	67	65
Other	1,418	1,221
Total other noncurrent assets	8,831	7,942
TOTAL ASSETS	$71,385	$ 68,012

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	September 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$750	$ 931
Long-term debt, classified as current	193	445
Accounts payable:		
Trade creditors	1,699	1,646
Regulatory balancing accounts	1,230	1,120
Other	556	517
Disputed claims and customer refunds	217	243
Interest payable	151	217
Wildfire-related claims	2,794	561
Other	1,899	1,449
Total current liabilities	9,489	7,129
Noncurrent Liabilities		
Long-term debt	18,407	17,753
Regulatory liabilities	8,607	8,679
Pension and other post-retirement benefits	2,014	2,128
Asset retirement obligations	4,999	4,899
Deferred income taxes	5,822	5,822
Other	2,351	2,130
Total noncurrent liabilities	42,200	41,411
Contingencies and Commitments (Note 9)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 517,102,983 and 514,755,845 shares outstanding at respective dates	12,833	12,632
Reinvested earnings	6,623	6,596
Accumulated other comprehensive loss	(12)	(8)
Total shareholders' equity	19,444	19,220
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	19,696	19,472
TOTAL LIABILITIES AND EQUITY	$71,385	$ 68,012

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2018	2017
Cash Flows from Operating Activities		
Net income	$32	$1,542
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	2,257	2,134
Allowance for equity funds used during construction	(97)	(63)
Deferred income taxes and tax credits, net	10	848
Disallowed capital expenditures	(38)	47
Other	231	204
Effect of changes in operating assets and liabilities:		
Accounts receivable	(201)	(58)
Wildfire-related insurance receivable	64	(166)
Inventories	(24)	(35)
Accounts payable	245	76
Wildfire-related claims	2,233	12
Income taxes receivable/payable	—	135
Other current assets and liabilities	(154)	23
Regulatory assets, liabilities, and balancing accounts, net	(128)	(30)
Other noncurrent assets and liabilities	(194)	68
Net cash provided by operating activities	4,236	4,737
Cash Flows from Investing Activities		
Capital expenditures	(4,592)	(3,938)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,121	1,043
Purchases of nuclear decommissioning trust investments	(1,165)	(1,071)
Other	19	16
Net cash used in investing activities	(4,617)	(3,950)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	775	—
Repayments under revolving credit facilities	(775)	—
Net issuances (repayments) of commercial paper, net of discount of $1 and $4 at respective dates	(182)	(652)
Short-term debt financing	250	250
Short-term debt matured	(250)	(250)
Proceeds from issuance of long-term debt, net of discount and issuance costs of $7 and $11 at respective dates	1,143	734
Long-term debt matured or repurchased	(750)	(345)
Common stock issued	137	345
Common stock dividends paid	—	(754)
Other	14	(101)
Net cash provided by (used in) financing activities	362	(773)
Net change in cash and cash equivalents	(19)	14
Cash and cash equivalents at January 1	449	177
Cash and cash equivalents at September 30	$430	$191

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(650)	$(644)
Income taxes, net	(49)	158
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$—	$272
Capital expenditures financed through accounts payable	348	301
Noncash common stock issuances	—	16
Terminated capital leases	161	—

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Operating Revenues				
Electric	$3,467	$3,647	$9,730	$10,038
Natural gas	915	869	2,942	2,999
Total operating revenues	4,382	4,516	12,672	13,037
Operating Expenses				
Cost of electricity	1,256	1,466	3,038	3,436
Cost of natural gas	69	78	437	524
Operating and maintenance	1,611	1,389	5,002	4,518
Wildfire-related claims, net of insurance recoveries	(10)	53	2,108	—
Depreciation, amortization, and decommissioning	759	710	2,257	2,134
Total operating expenses	3,685	3,696	12,842	10,612
Operating Income (Loss)	697	820	(170)	2,425
Interest income	14	10	34	22
Interest expense	(229)	(217)	(668)	(655)
Other income, net	103	38	321	93
Income (Loss) Before Income Taxes	585	651	(483)	1,885
Income tax provision (benefit)	14	138	(530)	394
Net Income	571	513	47	1,491
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$568	$510	$37	$1,481

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Net Income	$571	$513	$47	$1,491
Other Comprehensive Income				
Pension and other post-retirement benefit plans obligations (net of taxes of $0, $0, $0, and $0, at respective dates)	—	—	1	1
Total other comprehensive income	—	—	1	1
Comprehensive Income	$571	$513	$48	$1,492

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	September 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$371	$447
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $58 and $64 at respective dates)	1,297	1,243
Accrued unbilled revenue	962	946
Regulatory balancing accounts	1,326	1,222
Other	902	862
Regulatory assets	229	615
Inventories:		
Gas stored underground and fuel oil	116	115
Materials and supplies	389	366
Other	698	465
Total current assets	6,290	6,281
Property, Plant, and Equipment		
Electric	56,860	55,133
Gas	20,798	19,641
Construction work in progress	2,855	2,471
Total property, plant, and equipment	80,513	77,245
Accumulated depreciation	(24,308)	(23,456)
Net property, plant, and equipment	56,205	53,789
Other Noncurrent Assets		
Regulatory assets	4,429	3,793
Nuclear decommissioning trusts	2,917	2,863
Income taxes receivable	66	64
Other	1,289	1,094
Total other noncurrent assets	8,701	7,814
TOTAL ASSETS	$71,196	$67,884

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions. except share amounts)	(Unaudited) Balance At September 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$750	$ 799
Long-term debt, classified as current	193	445
Accounts payable:		
Trade creditors	1,699	1,644
Regulatory balancing accounts	1,230	1,120
Other	575	538
Disputed claims and customer refunds	217	243
Interest payable	149	214
Wildfire-related claims	2,794	561
Other	1,904	1,457
Total current liabilities	9,511	7,021
Noncurrent Liabilities		
Long-term debt	18,057	17,403
Regulatory liabilities	8,607	8,679
Pension and other post-retirement benefits	1,910	2,026
Asset retirement obligations	4,999	4,899
Deferred income taxes	5,960	5,963
Other	2,367	2,146
Total noncurrent liabilities	41,900	41,116
Contingencies and Commitments (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	8,505	8,505
Reinvested earnings	9,695	9,656
Accumulated other comprehensive income	5	6
Total shareholders' equity	19,785	19,747
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$71,196	$ 67,884

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2018	2017
Cash Flows from Operating Activities		
Net income	$47	$1,491
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	2,257	2,134
Allowance for equity funds used during construction	(97)	(63)
Deferred income taxes and tax credits, net	5	848
Disallowed capital expenditures	(38)	47
Other	170	196
Effect of changes in operating assets and liabilities:		
Accounts receivable	(200)	(58)
Wildfire-related insurance receivable	64	(166)
Inventories	(24)	(35)
Accounts payable	245	76
Wildfire-related claims	2,233	12
Income taxes receivable/payable	—	135
Other current assets and liabilities	(156)	36
Regulatory assets, liabilities, and balancing accounts, net	(128)	(30)
Other noncurrent assets and liabilities	(194)	69
Net cash provided by operating activities	4,184	4,692
Cash Flows from Investing Activities		
Capital expenditures	(4,592)	(3,938)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,121	1,043
Purchases of nuclear decommissioning trust investments	(1,165)	(1,071)
Other	19	16
Net cash used in investing activities	(4,617)	(3,950)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	650	—
Repayments under revolving credit facilities	(650)	—
Net issuances (repayments) of commercial paper, net of discount of $0 and $4 at respective dates	(50)	(652)
Short-term debt financing	250	250
Short-term debt matured	(250)	(250)
Proceeds from issuance of long-term debt, net of discount and issuance costs of $7 and $11 at respective dates	793	734
Long-term debt matured or repurchased	(400)	(345)
Preferred stock dividends paid	—	(10)
Common stock dividends paid	—	(784)
Equity contribution from PG&E Corporation	—	405
Other	14	(91)
Net cash provided by (used in) financing activities	357	(743)
Net change in cash and cash equivalents	(76)	(1)
Cash and cash equivalents at January 1	447	71
Cash and cash equivalents at September 30	$371	$70

Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(640)	$(636)
Income taxes, net	(59)	158
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$348	$301
Terminated capital leases	161	—

See accompanying Notes to the Condensed Consolidated Financial Statements.

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, 2017 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in Item 8 of the 2017 Form 10-K. This quarterly report should be read in conjunction with the 2017 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 post-retirement 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.

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

Cal Fire issued its determination on the causes of 17 of the Northern California wildfires, and alleged that each of these fires involved the Utility's equipment. The remaining wildfires remain under Cal Fire’s investigation, including the possible role of the Utility’s power lines and other facilities. Additionally, the Northern California wildfires are under investigation by the CPUC’s SED. See “Northern California Wildfires” in Note 9 below.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For a summary of the significant accounting policies used by PG&E Corporation and the Utility, see Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 September 30, 2018, 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 September 30, 2018, it did not consolidate any of them.

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 nine months ended September 30, 2018 and 2017 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
(in millions)	2018	2017	2018	2017
Service cost for benefits earned [1]	$128	$118	$16	$14
Interest cost	171	178	17	20
Expected return on plan assets	(255)	(193)	(33)	(24)
Amortization of prior service cost	(1)	(1)	4	4
Amortization of net actuarial loss	1	6	(1)	1
Net periodic benefit cost	44	108	3	15
Regulatory account transfer [2]	41	(23)	—	—
Total	$85	$85	$3	$15

[1] A portion of service costs are capitalized pursuant to ASU 2017-07.
[2] 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	
	Nine Months Ended September 30,			
(in millions)	2018	2017	2018	2017
Service cost for benefits earned [1]	$385	$354	$49	$44
Interest cost	515	535	52	58
Expected return on plan assets	(766)	(578)	(98)	(73)
Amortization of prior service cost	(4)	(5)	11	12
Amortization of net actuarial loss	4	17	(4)	3
Net periodic benefit cost	134	323	10	44
Regulatory account transfer [2]	118	(69)	—	—

Total	$252	$254	$10	$44

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

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

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

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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 September 30, 2018		
Beginning balance	$(30)	$ 17	$(13)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $0 and $1, respectively) [1]	(1)	3	2
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively) [1]	1	(1)	—
Regulatory account transfer (net of taxes of $0 and $1, respectively) [1]	1	(2)	(1)
Net current period other comprehensive gain (loss)	1	—	1
Ending balance	$(29)	$ 17	$(12)

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. (See the "Pension and Other Post-Retirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended September 30, 2017		
Beginning balance	$(25)	$ 17	$(8)
Amounts reclassified from other comprehensive income: [1]			
Amortization of prior service cost (net of taxes of $0 and $2, respectively)	(1)	2	1
Amortization of net actuarial loss (net of taxes of $2 and $0, respectively)	4	1	5
Regulatory account transfer (net of taxes of $2 and $2, respectively)	(3)	(3)	(6)
Net current period other comprehensive gain (loss)	—	—	—
Ending balance	$(25)	$ 17	$(8)

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. (See the "Pension and Other Post-Retirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Nine Months Ended September 30, 2018		
Beginning balance	$(25)	$ 17	$(8)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $1 and $3, respectively) [1]	(3)	8	5
Amortization of net actuarial loss (net of taxes of $1 and $1, respectively) [1]	3	(3)	—
Regulatory account transfer (net of taxes of $0 and $2, respectively) [1]	1	(5)	(4)
Reclassification of stranded income tax to retained earnings	(5)	—	(5)
Net current period other comprehensive gain (loss)	$(4)	$ —	$(4)
Ending balance	(29)	17	(12)

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. (See the “Pension and Other Post-Retirement Benefits” table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Nine Months Ended September 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 $5, respectively)	(3)	7	4
Amortization of net actuarial loss (net of taxes of $7 and $1, respectively)	10	2	12
Regulatory account transfer (net of taxes of $5 and $6, respectively)	(7)	(8)	(15)
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 post-retirement benefit costs. (See the “Pension and Other Post-Retirement 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 Standards

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-9, Revenue from Contracts with Customers (Topic 606), which amends the previous revenue recognition guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. PG&E Corporation and the Utility applied the requirements using the modified retrospective method when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Condensed Consolidated Financial Statements as of the adoption date or for the three and nine months ended September 30, 2018. A majority of the Utility’s revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customers' monthly consumption. Such revenue is recognized using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer.

Revenue from Contracts with Customers

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

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

Regulatory Balancing Account Revenue

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

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

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

(in millions)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Electric		
Revenue from contracts with customers		
Residential	$ 1,649	$ 4,023
Commercial	1,430	3,737
Industrial	448	1,126
Agricultural	523	966
Public street and highway lighting	18	55
Other [1]	(273)	(388)
Total revenue from contracts with customers - electric	3,795	9,519
Regulatory balancing accounts [2]	(328)	211
Total electric operating revenue	$ 3,467	$ 9,730
Natural gas		
Revenue from contracts with customers		
Residential	$ 242	$ 1,652
Commercial	87	402
Transportation service only	287	847
Other [1]	30	(149)
Total revenue from contracts with customers - gas	646	2,752
Regulatory balancing accounts [2]	269	190
Total natural gas operating revenue	915	2,942
Total operating revenues	$ 4,382	$ 12,672

[1] This activity is primarily related to the change in unbilled revenue, partially offset by other miscellaneous revenue items.

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

Presentation of Net Periodic Pension and Post-Retirement Benefit Costs

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715), which amends the guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. PG&E Corporation and the Utility applied the requirements when the ASU became effective on January 1, 2018.

On a retrospective basis, the amendment requires an employer to separate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. As a result, the Condensed Consolidated Statements of Income for PG&E Corporation and the Utility were restated. This change resulted in increases to Operating and maintenance expenses and Other income, net, of $13 million and $14 million for PG&E Corporation and the Utility, respectively, for the three months ended September 30, 2017 and $39 million and $41 million for PG&E Corporation and the Utility, respectively, for the nine months ended September 30, 2017.

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

Recognition and Measurement of Financial Assets and Financial Liabilities

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

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

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

Accounting Standards Issued But Not Yet Adopted

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the guidance relating to the definition of a lease, recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. Under the new standard, all lessees must recognize an asset and liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019, with early adoption permitted.

PG&E Corporation and the Utility intend to elect certain practical expedients and will carry forward historical conclusions related to (1) contracts that contain leases, (2) existing lease and easement classification, and (3) initial direct costs. Additionally, PG&E Corporation and the Utility do not intend to restate comparative periods upon adoption.

PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Condensed Consolidated Balance Sheets and do not expect the guidance will have a material impact on the Condensed Consolidated Statements of Income, Statements of Cash Flows and related disclosures.

Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurements, which amends the existing guidance relating to the disclosure requirements for fair value measurements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Intangibles-Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15, Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets and Liabilities

Long-Term Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Asset Balance at September 30, 2018	December 31, 2017
Pension benefits	$1,837	$ 1,954
Environmental compliance costs	851	837
Utility retained generation	285	319
Price risk management	67	65
Unamortized loss, net of gain, on reacquired debt	80	79
Catastrophic event memorandum account [1]	760	274
Wildfire expense memorandum account [2]	77	—
Fire hazard prevention memorandum account [3]	65	1
Other	407	264
Total long-term regulatory assets	$4,429	$ 3,793

[1] Represents costs related to certain catastrophic events that the Utility believes are probable of recovery. For more information, see Note 9 below.
[2] Represents costs related to insurance premiums that the Utility believes are probable of recovery. For more information, see Note 9 below.
[3] Represents costs related to wildfire prevention vegetation management work that the Utility believes are probable of recovery.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

(in millions)	Liability Balance at September 30, 2018	December 31, 2017
Cost of removal obligations	$5,888	$ 5,547
Deferred income taxes	437	1,021
Recoveries in excess of AROs	489	624
Public purpose programs	660	590
Other	1,133	897
Total long-term regulatory liabilities	$8,607	$ 8,679

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Regulatory Balancing Accounts

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

(in millions)	Receivable Balance at September 30, 2018	December 31, 2017
Electric distribution	$31	$ —
Electric transmission	109	139
Gas distribution and transmission	624	486
Energy procurement	131	71
Public purpose programs	120	103
Other	311	423
Total regulatory balancing accounts receivable	$1,326	$ 1,222

(in millions)	Payable Balance at September 30, 2018	December 31, 2017
Electric distribution	$—	$ 72
Electric transmission	132	120
Utility generation	70	14
Gas distribution and transmission	9	—
Energy procurement	69	149
Public purpose programs	588	452
Other	362	313
Total regulatory balancing accounts payable	$1,230	$ 1,120

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 September 30, 2018:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Facility Availability
PG&E Corporation	April 2022	$300 (1)	$ —	$ —	$ 300
Utility	April 2022	3,000 (2)	87	—	2,913
Total revolving credit facilities		$3,300	$ 87	$ —	$ 3,213

(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.

Other Short-term Borrowings

In February 2018, the Utility's $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. Additionally, in February 2018, the Utility entered into a $250 million floating rate unsecured term loan that will mature on February 22, 2019. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Long-term Debt Issuances and Redemptions

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

In April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. The term loan will mature on April 16, 2020, unless extended by PG&E Corporation pursuant to the terms of the term loan agreement. The proceeds were used for general corporate purposes, including the early redemption of PG&E Corporation’s outstanding $350 million principal amount of 2.40% Senior Notes due March 1, 2019. On April 26, 2018, PG&E Corporation completed the early redemption of these bonds, which satisfied and discharged its remaining obligation of $350 million.

In August 2018, the Utility issued $500 million principal amount of 4.25% Senior Notes due August 1, 2023 and $300 million principal amount of 4.65% Senior Notes due August 1, 2028. The proceeds will be used to repay $500 million floating rate Senior Notes due November 28, 2018, to repay a $250 million term loan maturing on February 22, 2019 and for general corporate purposes.

Variable Rate Interest

At September 30, 2018, 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 1.55% to 1.68%. At September 30, 2018, the interest rates on the $149 million principal amount of pollution control bonds Series 2009 A and B, and the related loan agreements, were 1.60%.

NOTE 5: EQUITY

PG&E Corporation’s and the Utility’s changes in equity for the nine months ended September 30, 2018 were as follows:

	PG&E Corporation	Utility
(in millions)	Total Equity	Total Shareholders' Equity
Balance at December 31, 2017	$ 19,472	$ 19,747
Comprehensive income	33	48
Common stock issued	137	—
Share-based compensation	64	—
Preferred stock dividend requirement	—	(10)
Preferred stock dividend requirement of subsidiary	(10)	—
Balance at September 30, 2018	$ 19,696	$ 19,785

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the nine months ended September 30, 2018. As of September 30, 2018, the remaining amount available under this agreement was $246.3 million.

PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan and share-based compensation plans. During the nine months ended September 30, 2018, 3.6 million shares were issued for cash proceeds of $136.7 million under these plans.

Dividends

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

The dividends declared per share on PG&E Corporation's common stock were $0 and $0.53, for the three months ended September 30, 2018 and 2017, respectively, and $0 and $1.55 for the nine months ended September 30, 2018 and 2017, respectively.

NOTE 6: EARNINGS PER SHARE

PG&E Corporation's basic EPS are 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 September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2018	2017	2018	2017
Income available for common shareholders	$564	$550	$22	$1,532
Weighted average common shares outstanding, basic	517	513	516	511
Add incremental shares from assumed conversions:				
Employee share-based compensation	—	3	1	3
Weighted average common shares outstanding, diluted	517	516	517	514
Total earnings per common share, diluted	$1.09	$1.07	$0.04	$2.98

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 counter-party. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the 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.

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Volume of Derivative Activity

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

Underlying Product	Instruments	Contract Volume at September 30, 2018	December 31, 2017
Natural Gas [1] (MMBtus [2])	Forwards, Futures and Swaps	250,021,802	228,768,745
	Options	29,534,224	60,736,806
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	3,939,691	2,872,013
	Congestion Revenue Rights [3]	316,451,690	312,272,177

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At September 30, 2018, the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$34	$ (2)	$ 5	$ 37
Other noncurrent assets – other	88	—	—	88
Current liabilities – other	(39)	2	12	(25)
Noncurrent liabilities – other	(67)	—	4	(63)
Total commodity risk	$16	$ —	$ 21	$ 37

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

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

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

The majority of the Utility's derivatives instruments, including certain power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. The Utility's credit rating remains investment grade. If the Utility 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 Utility held derivatives with a net liability fair value of $44 million and $1 million at September 30, 2018 and December 31, 2017, respectively, offset by an immaterial amount from related derivatives in an asset position. If the credit-risk-related contingency feature were triggered, at September 30, 2018, the Utility would be required to post additional collateral immediately in the amount of $12 million.

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.

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				
	September 30, 2018				
(in millions)	Level 1	Level 2	Level 3	Netting [1]	Total
Assets:					
Short-term investments	$377	—	—	—	$377
Nuclear decommissioning trusts					
Short-term investments	14	—	—	—	14
Global equity securities	1,970	—	—	—	1,970
Fixed-income securities	738	631	—	—	1,369
Assets measured at NAV	—	—	—	—	19
Total nuclear decommissioning trusts [2]	2,722	631	—	—	3,372
Price risk management instruments (Note 7)					
Electricity	1	5	110	2	118
Gas	—	6	—	1	7
Total price risk management instruments	1	11	110	3	125
Rabbi trusts					
Fixed-income securities	—	75	—	—	75
Life insurance contracts	—	68	—	—	68
Total rabbi trusts	—	143	—	—	143
Long-term disability trust					
Short-term investments	8	—	—	—	8
Assets measured at NAV	—	—	—	—	112
Total long-term disability trust	8	—	—	—	120
TOTAL ASSETS	$3,108	$785	$110	$ 3	$4,137
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$5	$12	$86	$ (17)	$86
Gas	—	3	—	(1)	2
TOTAL LIABILITIES	$5	$15	$86	$ (18)	$88

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $455 million, primarily related to deferred taxes on appreciation of investment value.

(in millions)	Fair Value Measurements December 31, 2017 Level 1	Level 2	Level 3	Netting [(1)]	Total
Assets:					
Short-term investments	$385	$—	$—	$—	$385
Nuclear decommissioning trusts					
Short-term investments	23	—	—	—	23
Global equity securities	1,967	—	—	—	1,967
Fixed-income securities	733	562	—	—	1,295
Assets measured at NAV	—	—	—	—	18
Total nuclear decommissioning trusts [(2)]	2,723	562	—	—	3,303
Price risk management instruments (Note 7)					
Electricity	—	3	129	6	138
Gas	—	1	—	—	1
Total price risk management instruments	—	4	129	6	139
Rabbi trusts					
Fixed-income securities	—	72	—	—	72
Life insurance contracts	—	71	—	—	71
Total rabbi trusts	—	143	—	—	143
Long-term disability trust					
Short-term investments	8	—	—	—	8
Assets measured at NAV	—	—	—	—	167
Total long-term disability trust	8	—	—	—	175
TOTAL ASSETS	$3,116	$709	$129	$6	$4,145
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$10	$15	$87	$(25)	$87
Gas	—	1	—	—	1
TOTAL LIABILITIES	$10	$16	$87	$(25)	$88

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

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the nine months ended September 30, 2018 and 2017.

Trust Assets

Assets Measured at Fair Value

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

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

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

Assets Measured at NAV Using Practical Expedient

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the 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.

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 September 30, 2018				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range [1]
Congestion revenue rights	$ 110	$ 44	Market approach	CRR auction prices	$ (18.61) - 32.26
Power purchase agreements	$ —	$ 42	Discounted cash flow	Forward prices	$ 19.81 - 38.80

[1] Represents price per megawatt-hour.

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

[1] Represents price per megawatt-hour.

Level 3 Reconciliation

The following tables present the reconciliation for Level 3 price risk management instruments for the three and nine months ended September 30, 2018 and 2017:

	Price Risk Management Instruments	
(in millions)	2018	2017
Asset (liability) balance as of July 1	$ 34	$ 48
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [1]	(10)	—
Asset (liability) balance as of September 30	$ 24	$ 48

[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.

	Price Risk Management Instruments	
(in millions)	2018	2017
Asset (liability) balance as of January 1	$ 42	$ 55
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [1]	(18)	(7)
Asset (liability) balance as of September 30	$ 24	$ 48

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

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at September 30, 2018 and December 31, 2017, as they are short-term in nature or have interest rates that reset daily.

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

	At September 30, 2018	At December 31, 2017
(in millions)		

	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
PG&E Corporation[1]	$350	$ 350	$350	$ 350
Utility	17,491	16,413	17,090	19,128

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

Nuclear Decommissioning Trust Investments

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

As of September 30, 2018	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
Nuclear decommissioning trusts				
Short-term investments	$ 14	$ —	$ —	$ 14
Global equity securities	478	1,513	(2)	1,989
Fixed-income securities	1,369	28	(28)	1,369
Total [1]	$ 1,861	$ 1,541	$ (30)	$ 3,372
As of December 31, 2017				
Nuclear decommissioning trusts				
Short-term investments	$ 23	$ —	$ —	$ 23
Global equity securities	524	1,463	(2)	1,985
Fixed-income securities	1,252	51	(8)	1,295
Total [1]	$ 1,799	$ 1,514	$ (10)	$ 3,303

[1] Represents amounts before deducting $455 million and $440 million for the periods ended September 30, 2018 and December 31, 2017, respectively, primarily related to deferred taxes on appreciation of investment value.

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

(in millions)	As of September 30, 2018
Less than 1 year	$ 69
1–5 years	401
5–10 years	386
More than 10 years	513
Total maturities of fixed-income securities	$ 1,369

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Proceeds from sales and maturities of nuclear decommissioning trust investments	$319	$249	$1,121	$1,043
Gross realized gains on securities	3	8	51	50
Gross realized losses on securities	(5)	—	(14)	(8)

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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 liability has been incurred and the amount of the liability can reasonably be estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred.

The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities.

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

Wildfire-Related Claims

Wildfire-related claims on the Condensed Consolidated Financial Statements include amounts associated with the Northern California wildfires and the Butte fire.

For the three and nine months ended September 30, 2018 and 2017, the Utility’s Condensed Consolidated Income Statements include estimated losses offset by insurance recoveries as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Butte fire				
Third-Party Claims	$—	$350	$—	$350
Insurance recoveries	—	(297)	(7)	(350)
Total Butte fire	—	53	(7)	—
Northern California wildfires				
Third-Party Claims	—	—	2,500	—
Insurance recoveries	(10)	—	(385)	—
Total Northern California wildfires	(10)	—	2,115	—
Total wildfire-related claims, net of insurance recoveries	$(10)	$53	$2,108	$—

In addition to the amounts shown in the table above, during the three and nine months ended September 30, 2018, the Utility incurred $53 million and $120 million, respectively, of legal and other costs related to the Northern California wildfires. See "Butte Fire" below for legal expenses related to the Butte Fire.

At September 30, 2018 and December 31, 2017, the Utility's Condensed Consolidated Balance Sheets include estimated losses as follows:

(in millions)	Balance At September 30, 2018	December 31, 2017
Butte fire	$ 294	$ 561
Northern California wildfires	2,500	—
Total wildfire-related claims	$ 2,794	$ 561

Northern California Wildfires

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

Cal Fire issued its determination on the causes of 17 of the Northern California wildfires, and alleged that each of these fires involved the Utility's equipment. The remaining wildfires remain under Cal Fire's investigation, including the possible role of the Utility's power lines and other facilities. Additionally, the Northern California wildfires are under investigation by the CPUC's SED.

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

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

On October 9, 2018, Cal Fire issued a news release announcing the results of its investigation into the Cascade fire, located in Yuba County, concluding the Cascade fire "was started by sagging power lines coming into contact during heavy winds" and that "the power line in question was owned by Pacific Gas and Electric Company." Also on October 9, 2018, the Office of the District Attorney of Yuba County issued a news release indicating that no criminal charges would be filed in relation to the Cascade fire. The Office of the District Attorney of Yuba County also indicated that it "reserves the right to review any additional information or evidence that may be submitted to it prior to the expiration of the criminal statute of limitations." On October 10, 2018, Cal Fire released its investigation report related to the Cascade fire.

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

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

As of October 30, 2018, the Utility had submitted 23 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire or the Utility has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary and does not reflect a determination of the causes of the fires.

Third-Party Claims

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision were to determine that the doctrine of inverse condemnation applies. In addition to such claims for property damage, business interruption, interest, and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.

As of October 30, 2018, PG&E Corporation and the Utility are aware of approximately 500 complaints on behalf of at least 3,100 plaintiffs related to the Northern California wildfires, five of which seek to be certified as class actions. These cases have been coordinated in the San Francisco Superior Court. The coordinated litigation is in the early stages of discovery. The litigation pending against PG&E Corporation and the Utility includes claims under multiple theories of liability, including inverse condemnation and negligence. Plaintiffs also seek punitive damages.

PG&E Corporation and the Utility also are the subject of investigations or other actions by the county District Attorneys to whom Cal Fire has referred its investigations into the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires. Although the Honey fire was referred to the Butte County District Attorney's Office, in October 2018, the Utility reached an agreement to settle any civil claims or criminal charges that could have been brought by the Butte County District Attorney in connection with the Honey fire, as well as the La Porte and Cherokee fires (which were not referred). The settlement provides for funding by the Utility for at least four years of an enhanced fire prevention and communication program, in the amount of up to $1.5 million, not recoverable in rates. On October 9, 2018, the District Attorney of Yuba County announced his decision not to pursue criminal charges at this time against PG&E Corporation or the Utility pertaining to the Cascade fire. Also in October 2018, the Utility and the Sonoma, Napa, Lake, Humboldt and Nevada County District Attorneys entered into agreements under which the Utility agreed to waive any applicable statutes of limitation related to the Northern California wildfires that started in these counties for a period of six months, until April 8, 2019. PG&E Corporation and the Utility anticipate further discussions with the District Attorneys in these counties relating to the Northern California wildfires and whether any criminal or civil charges should be brought.

Regardless of any determinations of cause by Cal Fire, ultimately PG&E Corporation and the Utility's liability will be resolved through litigation, regulatory proceedings and any potential enforcement proceedings, all of which could take a number of years to resolve. The timing and outcome of these and other potential proceedings are uncertain.

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

In addition, insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed 36 subrogation complaints in the San Francisco County Superior Court. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. Further, various government entities, including Mendocino, Napa and Sonoma Counties and the City of Santa Rosa, also asserted claims against PG&E Corporation and the Utility based on the damages that these public entities allegedly suffered as a result of the fires. Such alleged damages include, among other things, loss of natural resources, loss of public parks, property damages and fire suppression costs. The causes of action and allegations are similar to the ones made by individual plaintiffs and the insurance carriers.

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

PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved.

Estimated Losses from Third-Party Claims

Potential liabilities related to the Northern California wildfires depend on various factors, including but not limited to the cause of each fire, contributing causes of the fires (including alternative potential origins, weather- and climate-related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties or fines that may be imposed by governmental entities.

In light of the current state of the law on inverse condemnation and the information currently available to the Utility, including, among other things, the Cal Fire determinations of cause as stated in Cal Fire's press releases and their released reports, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with 14 of the Northern California wildfires referred to as the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket and Sonoma/Napa merged fires (which include the Nuns, Norrbom, Adobe, Partrick and Pythian fires), and accordingly, PG&E Corporation and the Utility recorded a charge in the amount of $2.5 billion during the quarter ended June 30, 2018. This charge corresponds to the lower end of the range of PG&E Corporation and the Utility's reasonably estimated losses and is subject to change based on additional information.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss will be greater than the amount accrued but are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the Northern California wildfires may change, which could result in material increases to the loss accrued.

The $2.5 billion charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any. It also does not include any amounts in connection with the Atlas, 37, Tubbs, Cascade, Maacama, Pressley and Point fires because at this time PG&E Corporation and the Utility have not concluded that a loss arising from those fires is probable. However, in the future it is possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability at that time, the amount of which could be significant.

On September 6, 2018, the California Department of Insurance issued a news release announcing an update on property losses in connection with the October and December 2017 wildfires in California. As of that date, insurers have received nearly 55,000 insurance claims totaling more than $12.28 billion in losses, of which approximately $10 billion relates to statewide claims from the Northern California wildfires. The balance relates to claims from the Southern California December 2017 wildfires. That news release reflected insured property losses only. Also, that amount did not account for uninsured losses, interest, attorneys' fees, fire suppression and clean-up costs, personal injury and wrongful death damages or other costs. If PG&E Corporation and the Utility were to be found liable for certain or all of such other costs and expenses, including the potential liabilities outlined above, the amount of the liability could significantly exceed the approximately $10 billion in estimated insured property losses with respect to the Northern California wildfires.

Loss Recoveries

PG&E Corporation and the Utility have liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $840 million, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. In addition, coverage limits within these wildfire insurance policies could result in further material self-insured costs in the event each fire were deemed to be a separate occurrence under the terms of the insurance policies.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through September 30, 2018, PG&E Corporation and the Utility recorded $385 million for probable insurance recoveries in connection with the Northern California wildfires. This amount reflects an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. The amount of the receivable is subject to change based on additional information. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future. If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected. Even if PG&E Corporation and the Utility were to recover the full amount of their insurance, the potential losses arising out of the Northern California wildfires could significantly exceed the coverage limits of the insurance.

The following table presents changes in the insurance receivable for the nine months ended September 30, 2018. The balance for 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)	
Accrued insurance recoveries	$385
Reimbursements	(13)
Balance at September 30, 2018	$372

In addition, it could take a number of years before the extent of the Utility's liability is known and the Utility could apply for recovery of costs in excess of insurance. On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA for the purpose of tracking specific incremental wildfire liability costs effective as of July 26, 2017. The decision does not grant the Utility rate recovery of any wildfire-related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. The Utility may be unable to fully recover costs in excess of insurance, if at all, and even if such recovery is possible, it could take a number of years to resolve and a number of years to collect.

As of September 30, 2018, the Condensed Consolidated Financial Statements include long-term regulatory assets of $77 million, consisting of insurance premium costs that are probable of recovery. Should PG&E Corporation and the Utility conclude in future periods that recovery of insurance premiums in excess of amounts included in authorized revenue requirements is no longer probable, PG&E Corporation and the Utility will record a charge in the period such conclusion is reached.

Failure to obtain a substantial or full recovery of costs related to the Northern California wildfires or any conclusion that such recovery is no longer probable could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Recently adopted Senate Bill 901 establishes a customer harm threshold, directing the CPUC to limit disallowances in the aggregate, so that they do not exceed the maximum amount that PG&E Corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service. It is uncertain how the new legislation will affect the Utility's ability to recover costs related to the Northern California wildfires. PG&E Corporation and the Utility have considered actions that might be taken to attempt to address liquidity needs of the business should the Utility be unable to recover costs related to the Northern California wildfires, but the inability to recover costs in excess of insurance through increases in rates or to collect such rates in a timely manner could have a material adverse effect on PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows.

Derivative Litigation

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

On August 3, 2018, a third purported derivative lawsuit entitled Oklahoma Firefighters Pension and Retirement System v. Chew, et al., was filed in the U.S. District Court for the Northern District of California, naming as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation is named as a nominal defendant. The lawsuit alleges claims for breach of fiduciary duties and unjust enrichment as well as a claim under Section 14(a) of the federal Securities Exchange Act of 1934 alleging that PG&E Corporation's and the Utility's 2017 proxy statement contained misrepresentations regarding the companies' risk management and safety programs. PG&E Corporation's motion to stay the litigation was filed on October 15, 2018. Plaintiffs' opposition to that motion currently is due November 29, 2018, and defendants' reply brief in support of that motion currently is due December 24, 2018. The hearing on PG&E Corporation's motion to stay currently is set for January 31, 2019.

On October 23, 2018, a fourth purported derivative lawsuit entitled City of Warren Police and Fire Retirement System v. Chew, et al. was filed in San Francisco County Superior Court, alleging claims for breach of fiduciary duty, corporate waste and unjust enrichment. It names as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation, and names PG&E Corporation as a nominal defendant.

PG&E Corporation and the Utility are unable to predict the timing and outcome of these proceedings.

Securities Class Action Litigation

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California, naming PG&E Corporation and certain of its current and former officers as defendants, entitled David C. Weston v. PG&E Corporation, et al. and Jon Paul Moretti v. PG&E Corporation, et al., respectively. The complaints allege material misrepresentations and omissions related to, among other things, vegetation management and transmission line safety in various PG&E Corporation public disclosures. The complaints assert claims under Section 10(b) and Section 20(a) of the federal Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder, and seek unspecified monetary relief, interest, attorneys' fees and other costs. Both complaints identify a proposed class period of April 29, 2015 to June 8, 2018. On September 10, 2018, the court consolidated both cases and the litigation is now denominated In Re PG&E Corporation Securities Litigation. The court also appointed the Public Employees Retirement Association of New Mexico as lead plaintiff. Plaintiffs currently have until November 9, 2018 to file an amended consolidated complaint and defendants currently have until January 8, 2019 to move to dismiss, answer or otherwise respond to that complaint. PG&E Corporation and the Utility are unable to predict the timing and outcome of these proceedings.

Clean-up and Repair Costs

The Utility incurred costs of $308 million for clean-up and repair of the Utility’s facilities (including $145 million in capital expenditures) through September 30, 2018, in connection with the Northern California wildfires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The Utility capitalizes and records as regulatory assets costs that are probable of recovery in rates. At September 30, 2018, the CEMA balance related to the Northern California wildfires was $101 million and reflects an approximately $40 million reduction to the regulatory asset that was recorded in the three months ended June 30, 2018, for costs that are no longer probable of recovery.

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

Butte Fire

In September 2015, a wildfire (known as the “Butte fire”) ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire’s report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire’s report concluded that the wildfire was caused when a gray pine tree contacted the Utility’s electric line, which ignited portions of the tree and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California, County of Sacramento. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council previously had authorized the coordination of all cases in Sacramento County. As of October 30, 2018, 95 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 4,000 individual plaintiffs representing approximately 2,100 households and their insurance companies. These complaints are part of or are in the process of being added to the coordinated proceeding. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. Several plaintiffs have dismissed the Utility's two vegetation management contractors from their complaints. The Utility does not expect the number of individual complaints and plaintiffs to increase significantly in the future, because the statute of limitations for property damage and personal injury in connection with the Butte fire has expired. The Utility continues to mediate and settle cases.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs’ claims for punitive damages. The court denied the Utility’s motion and the Utility filed a writ with the Court of Appeal of the State of California, Third Appellate District. The writ was granted on July 2, 2018, directing the trial court to enter summary adjudication in favor of the Utility and to deny plaintiffs' claim for punitive damages under California Civil Code Section 3294. Plaintiffs sought rehearing and asked the California Supreme Court to review the Court of Appeal's decision. Both requests were denied. Neither the trial nor appellate courts addressed whether plaintiffs can seek punitive damages at trial under Public Utilities Code Section 2106. Based on the July 2, 2018 Court of Appeal's ruling, the Utility believes a loss related to punitive damages is remote.

On June 22, 2017, the Superior Court of California, County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding at the time of the ruling, others could file lawsuits and make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases.

On May 1, 2018, the Superior Court of California, County of Sacramento issued its ruling on the Utility's renewed motion in which the court affirmed, with minor changes, its tentative ruling dated April 25, 2018. The court determined that it is bound by earlier holdings of two appellate courts decisions, Barham and Pacific Bell. Further, the court stated that the Utility's constitutional arguments should be made to the appellate courts and suggested that, to the extent the Utility raises the public policy implications of the November 30, 2017 CPUC decision in the San Diego Gas & Electric Company cost recovery proceeding, these arguments should be addressed to the Legislature or CPUC. The Utility filed a writ with the Court of Appeal seeking immediate review of the court's decision. On June 18, 2018, after the writ was summarily denied, the Utility filed a Petition for Review with the California Supreme Court, which also was denied. On September 6, 2018, the court set a trial for some individual plaintiffs to begin on April 1, 2019. The Utility reached agreement with two plaintiffs in the litigation to stipulate to judgment against the Utility on inverse condemnation grounds. If the court grants the motion on November 29, 2018, the Utility will have the right to an appellate court hearing on inverse condemnation.

In addition to the coordinated plaintiffs, Cal Fire, the California Office of Emergency Services (OES), the County of Calaveras, and five smaller public entities (three fire districts, one water district and the California Department of Veterans Affairs) have brought suit or indicated that they intend to do so. These five public entities filed their complaints in August 2018 and September 2018. They are being added to the coordinated proceedings.

On April 13, 2017, Cal Fire filed a complaint with the Superior Court of California, County of Calaveras, seeking to recover over $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, or violated the law, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Trees, Inc., one of the Utility's vegetation contractors. Cal Fire has requested that a trial of its claims be set in 2019, following any trial of the claims of the individual plaintiffs. On October 19, 2018, the Utility filed a motion for summary judgment arguing that Cal Fire cannot recover any fire suppression costs under the Third District Court of Appeal's decision in Dep't of Forestry & Fire Prot. v. Howell (2017) 18 Cal. App. 5th 154. The hearing on that motion is set for January 31, 2019. The Utility and Cal Fire are also engaged in a mediation process.

Also, on February 20, 2018, the County of Calaveras filed suit against the Utility and the Utility’s vegetation management contractors to recover damages and other costs, based on the doctrine of inverse condemnation and negligence theory of liability. The County also seeks punitive damages. On March 2, 2018, the County served a mediation demand seeking in excess of $167 million, having previously indicated that it intended to bring an approximately $85 million claim against the Utility. This claim included costs that the County of Calaveras allegedly incurred or expected to incur for infrastructure damage, erosion control, and other costs. The Utility and the County of Calaveras currently are engaged in a mediation process. The County has also requested a trial to take place no later than summer 2019. Based on statements by the court, the Utility anticipates that trial would take place, if at all, after a trial of individual plaintiffs' claims and the separate trial of Cal Fire claims.

Further, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates to be approximately $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. The Utility has not received any information or documentation from OES since its May 2017 statement. In June 2017, the Utility entered into an agreement with the OES that extends their deadline to file a claim to December 2020.

Estimated Losses from Third-Party Claims

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

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

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

The Utility has determined that it is probable that it will incur a loss of at least $1.1 billion in connection with the Butte fire. The Utility estimates it is reasonably possible that it may incur an additional $200 million, for a total loss of $1.3 billion. While these amounts include the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), and the County of Calaveras claim, they do not include any portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate any liability it may have for that additional claim.

The process for estimating costs associated with claims relating to the 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 the potential claim from the OES, outcomes of future court or jury decisions, and information about damages, for which the Utility could be liable, 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 Wildfire-related claims 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	350
Payments [1]	(479)
Balance at December 31, 2017	561
Accrued losses	—
Payments [1]	(267)
Balance at September 30, 2018	$294

[1] As of September 30, 2018, the Utility has paid $806 million of the $832 million in settlements to date in connection with the Butte fire.

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $118 million in connection with the Butte fire. For the three and nine months ended September 30, 2018, the Utility incurred legal expenses in connection with the Butte fire of $9 million and $31 million, respectively.

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.

Loss Recoveries

The Utility has liability insurance from various insurers, that provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through September 30, 2018, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility has received $60 million in cumulative reimbursements from the insurance policies of its vegetation management contractors (excluded from the table below), including $7 million received in the nine months ended September 30, 2018. Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's 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	297
Reimbursements	(276)
Balance at December 31, 2017	596
Accrued insurance recoveries	—
Reimbursements	(436)
Balance at September 30, 2018	$160

In October 2018, the Utility received an additional $45 million in insurance reimbursements.

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 a gray pine tree 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, without admitting liability or agreeing with the findings.

Enforcement Matters

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

Regulatory Proceedings

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

On April 26, 2018, the CPUC approved the revised proposed decision issued on April 3, 2018, adopting the settlement agreement jointly submitted to the CPUC on March 28, 2017, as modified (the "settlement agreement") by the Utility, the Cities of San Bruno and San Carlos, Cal PA (formerly known as the Office of Ratepayer Advocates or ORA), the SED, and TURN.

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

The CPUC also ordered a second phase in this proceeding to determine if any of the additional communications that the Utility reported to the CPUC on September 21, 2017, violate the CPUC ex parte rules. On May 22, 2018, the assigned ALJ issued a ruling requiring the parties to meet and confer to determine if an agreement can be reached on the issues identified by the ALJ. On September 17, 2018, the parties submitted a joint status report indicating a settlement in principle could not be reached. The ALJ will hold a prehearing conference with the parties to determine if evidentiary hearings are required. The Utility is unable to predict the timing and outcome of the second phase in this proceeding.
As a result of the CPUC's April 26, 2018 decision, on May 17, 2018, the Utility made a $12 million payment to the California General Fund and $6 million payments to each of the Cities of San Bruno and San Carlos. At September 30, 2018, PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets include a $24 million accrual for a portion of the 2018 GT&S revenue requirement reduction. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

For more information about the proceeding, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

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

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case and the Utility filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. The Utility expects the FERC to issue a final decision in the TO18 rate case by mid-2019. On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined in the TO18 final decision. The Utility is unable to predict the outcomes of FERC’s decisions in these proceedings.

Natural Gas Transmission Pipeline Rights-of-Way

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

Potential Safety Citations

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. 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, and the outcome of which could result in material fines and other penalties that could be imposed on the Utility. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation.

If the SED 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. Effective January 1, 2019, the maximum statutory penalty increases to $100,000. 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. 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. Historically, the SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. In the past, the SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The CPUC can also open an OII and levy additional fines even after the SED has issued a citation.

The Utility is unable to reasonably estimate the amount or range of future charges as a result of SED investigations or any proceedings that could be commenced in connection with potential violations of electric and natural gas laws and regulations.

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 $94 million at September 30, 2018, and $86 million at December 31, 2017. These amounts are included in Other current liabilities in the Condensed

Consolidated Balance Sheets. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows.

Disallowance of Plant Costs

2015 GT&S Rate Case Capital Disallowance

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. Additional charges may be required in the future based on the outcome of the CPUC's audit of 2011 through 2014 capital spending. Capital disallowances are reflected in operating and maintenance expenses in the Condensed Consolidated Statements of Income. For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 comprised of the following:

	Balance at	
(in millions)	September 30, 2018	December 31, 2017
Topock natural gas compressor station	$362	$ 334
Hinkley natural gas compressor station	151	147
Former manufactured gas plant sites owned by the Utility or third parties (1)	375	320
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	116	115
Fossil fuel-fired generation facilities and sites (3)	136	123
Total environmental remediation liability	$1,140	$ 1,039

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

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

The Utility's environmental remediation liability at September 30, 2018, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans and the Utility's time frame for remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition, and cash flows during the period in which they are recorded. At September 30, 2018, the Utility expected to recover $797 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

For more information, see remediation site descriptions below and see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Natural Gas Compressor Station Sites

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

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018 and will continue for several years. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $299 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $138 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $508 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $136 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $88 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Wildfire Insurance

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

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

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL and European Mutual Association for Nuclear Insurance, 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 retrospective assessment. If NEIL were to exercise this assessment, as of September 30, 2018, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $47 million. If European Mutual Association for Nuclear Insurance losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $3 million, as of September 30, 2018. 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 2017 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 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 September 30, 2018 and December 31, 2017, respectively, the Condensed Consolidated Balance Sheets reflected $217 million and $243 million in net claims within Disputed claims and customer refunds. 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 September 30, 2018, it is reasonably possible that unrecognized tax benefits will decrease by approximately $10 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduced the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminated bonus depreciation for utilities. Passage of the Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility recorded reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC staff in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017. As a result of updated amounts used in PG&E Corporation and the Utility's 2017 tax returns, during the nine months ended September 30, 2018, the Utility recorded a $12 million tax benefit to adjust provisional tax expense recorded at December 31, 2017, for the Tax Act. For the nine months ended September 30, 2018, the Utility recorded an $80 million reduction to the regulatory liability recorded at December 31, 2017 for the Tax Act.

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, 2017, the Utility had undiscounted future expected obligations of approximately $44 billion. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.) The Utility has not entered into any new material commitments during the nine months ended September 30, 2018.

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 2017 Form 10-K.

Northern California Wildfires

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

Cal Fire issued its determination on the causes of 17 of the Northern California wildfires, and alleged that each of these fires involved the Utility's equipment. The remaining wildfires remain under Cal Fire's investigation, including the possible role of the Utility's power lines and other facilities. Additionally, the Northern California wildfires are under investigation by the CPUC's SED. For more information, see Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

PG&E Corporation and the Utility’s financial condition, results of operations, liquidity and cash flows could be materially affected by additional potential losses resulting from the impact of the Northern California wildfires. See “Item 1A. Risk Factors” in the 2017 Form 10-K and in Part II below under “Item 1A. Risk Factors.”

Community Wildfire Safety Program

The Utility is implementing a comprehensive community wildfire safety program in coordination with first responders, civic and community leaders, and customers to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather events. The community wildfire safety program focuses on three areas: enhancing the Utility's situational awareness, monitoring potential fire threats across the Utility's service area in real time and coordinating prevention and response efforts; hardening the electric system, increasing grid resilience; and updating the Utility's operational practices to align with changing conditions, including programs for enhanced vegetation management, public safety power shut off, and recloser protocols. (See FHPMA in "Regulatory Matters" and "SB 901" in Legislative and Regulatory Initiatives below.)

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduced the federal income tax rate from 35% to 21% beginning on January 1, 2018, and eliminated bonus depreciation for utilities. Passage of the Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility recorded reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC staff in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017. As a result of updated amounts used in PG&E Corporation and the Utility's 2017 tax returns, during the nine months ended September 30, 2018, the Utility recorded a $12 million tax benefit to adjust provisional tax expense recorded at December 31, 2017, for the Tax Act. For the nine months ended September 30, 2018, the Utility recorded an $80 million reduction to the regulatory liability recorded at December 31, 2017 for the Tax Act.

On March 30, 2018, the Utility submitted to the CPUC PFMs of the CPUC's final decisions in the Utility's 2017 GRC and the 2015 GT&S rate case. The Utility also submitted updated testimony in connection with the 2019 GT&S rate case. These submittals reflect the effects of the Tax Act on these rate cases. On an aggregate basis from these submittals, the Utility anticipates an annual reduction to revenue requirements of approximately $325 million starting in 2018, and incremental increases to rate base of approximately $271 million for 2018 (including the impact of the private letter ruling advice letter approved by the CPUC on July 18, 2018), and $613 million for 2019. The incremental increases to rate base are due primarily to the elimination of bonus depreciation. On May 14, 2018, the Utility filed a proposal to reflect the impact of the Tax Act on its TO tariff rates effective March 1, 2018, in the resolution of the TO19 rate case. On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with the TO19 rate case. As a result of the TO19 settlement, the Utility anticipates an annual Tax Act related revenue requirement reduction of approximately $131 million (with a corresponding increase to rate base of $59 million) to impact its TO19 tariff rates effective March 14, 2018. The Utility is unable to predict the timing and outcome of the CPUC and FERC decisions in connection with these submittals.

Summary of Changes in Net Income and Earnings per Share

The tables below include a summary reconciliation of PG&E Corporation's consolidated income available for common shareholders and EPS to earnings from operations and EPS based on earnings from operations for the three and nine months ended September 30, 2018 as compared to the same periods in 2017 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 nine months ended September 30, 2018 as compared to the same period in 2017. "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 planning, and employee incentive compensation. PG&E Corporation believes that non-GAAP 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. Non-GAAP 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 September 30,				Nine Months Ended September 30,			
	Earnings		Earnings per Common Share (Diluted)		Earnings		Earnings per Common Share (Diluted)	
(in millions, except per share amounts)	2018	2017	2018	2017	2018	2017	2018	2017
PG&E Corporation's Earnings on a GAAP basis	$564	$550	$1.09	$1.07	$22	$1,532	$0.04	$2.98
Items Impacting Comparability: (1)								
Northern California wildfire-related costs, net of insurance (2)	31	—	0.06	—	1,639	—	3.17	—
Pipeline-related expenses (3)	9	12	0.02	0.02	25	45	0.05	0.09
Butte fire-related costs, net of insurance (4)	6	42	0.01	0.08	17	27	0.03	0.05
Reduction in gas-related capital disallowances (5)	(27)	—	(0.05)	—	(27)	—	(0.05)	—
2017 insurance premiums cost recoveries (6)	—	—	—	—	(23)	—	(0.05)	—
Fines and penalties (7)	—	11	—	0.02	—	47	—	0.09
Diablo Canyon settlement-related disallowance (8)	—	—	—	—	—	32	—	0.06
Legal and regulatory-related expenses (9)	—	1	—	—	—	5	—	0.01
GT&S revenue timing impact (10)	—	—	—	—	—	(88)	—	(0.17)
Net benefit from derivative litigation settlement (11)	—	(38)	—	(0.07)	—	(38)	—	(0.07)
PG&E Corporation's Non- GAAP Earnings from Operations (12)	$582	$578	$1.13	$1.12	$1,652	$1,562	$3.19	$3.04

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 27.98 percent for 2018 and 40.75 percent for 2017, except for certain fines and penalties in 2017. Amounts may not sum due to rounding.

(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, net of insurance, of $43 million (before the tax impact of $12 million) and $2.3 billion (before the tax impact of $637 million) during the three and nine months ended September 30, 2018, respectively, associated with the Northern California wildfires. This includes accrued charges of $2.5 billion (before the tax impact of $700 million) during the nine months ended September 30, 2018, related to estimated third-party claims in

connection with 14 of the Northern California wildfires. The Utility also recorded $53 million (before the tax impact of $15 million) and $120 million (before the tax impact of $34 million) during the three and nine months ended September 30, 2018, respectively for legal and other costs. In addition, the Utility incurred costs of $40 million (before the tax impact of $11 million) during the nine months ended September 30, 2018 for Utility clean-up and repair costs. These costs were partially offset by $10 million (before the tax impact of $3 million) and $385 million (before the tax impact of $108 million) recorded during the three and nine months ended September 30, 2018, respectively, for probable insurance recoveries.

(3) The Utility incurred costs of $13 million (before the tax impact of $4 million) and $35 million (before the tax impact of $10 million) during the three and nine months ended September 30, 2018, respectively, for pipeline-related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

(4) The Utility incurred costs, net of insurance, of $9 million (before the tax impact of $3 million) and $24 million (before the tax impact of $7 million) during the three and nine months ended September 30, 2018, respectively, associated with legal costs for the Butte fire. These costs were partially offset by $7 million (before the tax impact of $2 million) recorded during the nine months ended September 30, 2018 for contractor insurance recoveries.

(5) The Utility reduced the estimated disallowance for gas-related capital costs that were expected to exceed authorized amounts by $38 million (before the tax impact of $11 million) during the three and nine months ended September 30, 2018. The Utility had previously recorded $85 million (before the tax impact of $35 million) in 2016 for probable capital disallowances in the 2015 GT&S rate case. From 2012 through 2014, the Utility had recorded cumulative charges of $665 million (before the tax impact of $271 million) for disallowed Pipeline Safety Enhancement Plan-related capital expenditures.
(6) As a result of the CPUC June 2018 decision authorizing a WEMA, the Utility recorded $32 million (before the tax impact of $9 million) during the nine months ended September 30, 2018 for probable cost recoveries of insurance premiums incurred in 2017 above amounts included in authorized revenue requirements.
(7) The Utility incurred costs of $11 million (not tax deductible) and $71 million (before the tax impact of $24 million) during the nine months ended September 30, 2017, respectively, for fines and penalties. This included disallowed expenses of $32 million (before the tax impact of $13 million) during the nine months ended September 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 nine months ended September 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 $11 million (not tax deductible) and $24 million (before the tax impact of $5 million) during the nine months ended September 30, 2017, for financial remedies in connection with the settlement filed with the CPUC on March 28, 2017, related to the order instituting investigation into compliance with ex parte communication rules.
(8) The Utility recorded a disallowance of $47 million (before the tax impact of $15 million) during the nine months ended September 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), as a result of the settlement agreement submitted to the CPUC in connection with the Utility's joint proposal to retire the Diablo Canyon Power Plant.
(9) The Utility incurred costs of $2 million (before the tax impact of $1 million) and $9 million (before the tax impact of $4 million) during the three and nine months ended September 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.
(10) The Utility recorded revenues of $150 million (before the tax impact of $62 million) during the nine months ended September 30, 2017 in excess of the 2017 authorized revenue requirement, which included the final component of under-collected revenues retroactive to January 1, 2015, as a result of the CPUC's final phase two decision in the 2015 GT&S rate case.
(11) PG&E Corporation recorded proceeds from insurance, net of plaintiff payments, of $65 million (before the tax impact of $27 million) during the three and nine months ended September 30, 2017, associated with the settlement agreement in connection with the San Bruno shareholder derivative litigation that was approved by the Superior Court of California, County of San Mateo, on July 18, 2017. This included $90 million (before the tax impact of $37 million) during the three and nine months ended September 30, 2017, for proceeds from insurance, partially offset by $25 million (before the tax impact of $10 million) during the three and nine months ended September 30, 2017, for plaintiff legal fees paid in connection with the settlement.
(12) "Non-GAAP earnings from operations" is a non-GAAP financial measure.

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

	Third Quarter 2018 vs. 2017		Year to Date 2018 vs. 2017	
(in millions, except per share amounts)	Earnings	Earnings per Common Share (Diluted)	Earnings	Earnings per Common Share (Diluted)

2017 Non- GAAP Earnings from Operations [1]	$578	$ 1.12	$1,562	$ 3.04
Growth in rate base earnings	32	0.06	97	0.18
Timing of taxes [2]	12	0.02	13	0.02
Insurance premium cost recoveries [3]	6	0.01	33	0.06
Resolution of regulatory items [4]	—	—	29	0.06
Timing and duration of nuclear refueling outages	—	—	12	0.02
Timing of 2017 operational spend [5]	(31)	(0.06)	(31)	(0.06)
Decrease in authorized return on equity [6]	(7)	(0.01)	(21)	(0.03)
Tax impact of stock compensation [7]	—	—	(44)	(0.08)
Increase in shares outstanding	—	—	—	(0.02)
Miscellaneous	(8)	(0.01)	2	—
2018 Non-GAAP Earnings from Operations [1]	$582	$ 1.13	$1,652	$ 3.19

[1] See first table above for a reconciliation of EPS on a GAAP basis to non-GAAP EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 27.98 percent for 2018 and 40.75 percent for 2017, except for the tax impact of stock compensation. See Footnote 7 below. Amounts may not sum due to rounding.
[2] Represents the timing of taxes reportable in quarterly statements in accordance with Accounting Standards Codification 740, Income Taxes, and results from variances in the percentage of quarterly earnings to annual earnings.
[3] Represents insurance premium costs incurred during the three and nine months ended September 30, 2018, above amounts included in authorized revenue requirements, that are probable of recovery as a result of the CPUC's June 2018 decision authorizing a WEMA.
[4] Represents the impact of various regulatory outcomes during the nine months ended September 30, 2018.
[5] Represents the timing of operational expense spending during the three and nine months ended September 30, 2018, as compared to the same period in 2017.
[6] Represents the decrease in return on equity from 10.40 percent in 2017 to 10.25 percent in 2018 as a result of the 2017 CPUC final decision approving an additional extension to the original 2013 Cost of Capital decision.
[7] Represents the impact of income taxes related to share-based compensation awards under the Long-Term Incentive Plan that vested during the nine months ended September 30, 2018, as compared to the same period in 2017.

Key Factors Affecting Financial Results

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

- The Impact of the Northern California Wildfires. PG&E Corporation and the Utility face several uncertainties in connection with the Northern California wildfires, related to: the amount of additional possible loss related to third party claims (the Utility recorded a charge of $2.5 billion, which reflects the low end of the range of loss); recoverability of clean-up and repair costs (the Utility incurred costs of $308 million for clean-up and repair of the Utility's facilities through September 30, 2018); fines or penalties, which could be material, if the CPUC or any law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations; the applicability of the doctrine of inverse condemnation in the Northern California wildfires litigation, which the Utility continues challenging in courts; the recoverability of the above mentioned costs even if a court decision imposes liability under the doctrine of inverse condemnation, and the maximum amount that the CPUC is expected to determine, as a result of SB 901, that the Utility can pay without harming customers or materially impacting its ability to provide adequate and safe service. (See Notes 3 and 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and "Item 1A. Risk Factors" in the 2017 Form 10-K and in Part II below under "Item 1A. Risk Factors.")

- The Utility's Compliance with the CPUC Capital Structure. The CPUC's capital structure decisions require the Utility to maintain a 52% equity ratio on average over the period that the authorized capital structure is in place, and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its equity ratio below 51%. The capital structure condition waiver would be subject to CPUC approval. The net charges the Utility recorded in connection with the Northern California wildfires to date, and described herein, did not result in noncompliance by the Utility with its authorized capital structure. However, in the future, maintaining compliance with the Utility's authorized capital structure may require PG&E Corporation to issue a significant amount of equity, depending on the timing and amount of any claims payments and whether additional charges are recorded. If the Utility submits an application to the CPUC for a waiver to its capital structure condition, the Utility shall not be considered in violation of the condition during the period the waiver application is pending resolution.

- The Timing and Outcome of Ratemaking Proceedings. The Utility's financial results may be impacted by the timing and outcome of its 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19, and TO20 rate cases, future cost of capital proceedings, as well as the remand decision by the Ninth Circuit regarding an ROE incentive adder for transmission facilities, and its ability to timely recover costs not in rates already incurred and to be incurred in the future, including those tracked in its 2018 CEMA filing, WEMA and FHPMA, and insurance premiums in excess of the Utility's currently authorized revenue requirements. The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors. (See Notes 3 and 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and "Regulatory Matters" below.)

- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation's and the Utility's ability to access the capital markets, ability to borrow under their loan financing arrangements, and the terms and rates of future financings could be materially affected by the outcome of, or market perception of, the matters discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the nine months ended September 30, 2018, PG&E Corporation issued $137 million of common stock and made no equity contributions to the Utility. PG&E Corporation may seek to issue additional equity to pay claims, losses, fines, and penalties that may be required by the outcome of litigation and enforcement matters. Additional issuances of equity, if any, could have a material dilutive impact on

PG&E Corporation’s EPS.

- The Outcome of Enforcement, Litigation, and Regulatory Matters. The Utility's 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 the outcome of phase two of the ex parte OII, the potential recommendations that the third-party monitor (retained by the Utility in the first quarter of 2017 as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction) may make, and potential penalties in connection with the Utility's safety and other self-reports. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Changes in the Utility Industry. 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 goals, 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 while continuing to provide customers with safe, reliable, and affordable service. (See "Other Regulatory Proceedings" below.)

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in the 2017 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 (loss) available for common shareholders for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Consolidated Total	$564	$550	$22	$1,532
PG&E Corporation	(4)	40	(15)	51
Utility	$568	$510	$37	$1,481

PG&E Corporation's net income (loss) primarily consists of income taxes and interest expense on long-term debt. The decreases in PG&E Corporation's net income for the three and nine months ended September 30, 2018 as compared to the same periods in 2017 are primarily due to the impact of the San Bruno Derivative Litigation in 2017 with no corresponding activity in 2018, partially offset by additional income taxes in 2017.

Utility

The tables below show certain items from the Utility's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2018 and 2017. 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 September 30, 2018 Revenues/Costs:			Three Months Ended September 30, 2017 Revenues/Costs:		
	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$1,996	$ 1,471	$3,467	$2,002	$ 1,645	$3,647
Natural gas operating revenues	778	137	915	722	147	869
Total operating revenues	2,774	1,608	4,382	2,724	1,792	4,516
Cost of electricity	—	1,256	1,256	—	1,466	1,466
Cost of natural gas	—	69	69	—	78	78
Operating and maintenance	1,247	364	1,611	1,127	262	1,389
Wildfire-related claims, net of insurance recoveries	(10)	—	(10)	53	—	53
Depreciation, amortization, and decommissioning	759	—	759	710	—	710
Total operating expenses	1,996	1,689	3,685	1,890	1,806	3,696
Operating income (loss)	778	(81)	697	834	(14)	820
Interest income	14	—	14	10	—	10
Interest expense	(229)	—	(229)	(217)	—	(217)
Other income, net	22	81	103	24	14	38
Income before income taxes	$585	$—	$585	$651	$—	$651
Income tax provision (1)			14			138
Net income			571			513
Preferred stock dividend requirement (1)			3			3
Income Available for Common Stock			$568			$510

(1) These items impacted earnings for the three months ended September 30, 2018 and 2017.

(in millions)	Nine Months Ended September 30, 2018 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Nine Months Ended September 30, 2017 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$5,911	$3,819	$9,730	$5,933	$4,105	$10,038
Natural gas operating revenues	2,268	674	2,942	2,261	738	2,999
Total operating revenues	8,179	4,493	12,672	8,194	4,843	13,037
Cost of electricity	—	3,038	3,038	—	3,436	3,436
Cost of natural gas	—	437	437	—	524	524
Operating and maintenance	3,742	1,260	5,002	3,594	924	4,518
Wildfire-related claims, net of insurance recoveries	2,108	—	2,108	—	—	—
Depreciation, amortization, and decommissioning	2,257	—	2,257	2,134	—	2,134
Total operating expenses	8,107	4,735	12,842	5,728	4,884	10,612
Operating income (loss)	72	(242)	(170)	2,466	(41)	2,425
Interest income	34	—	34	22	—	22
Interest expense	(668)	—	(668)	(655)	—	(655)
Other income, net	79	242	321	52	41	93
Income (loss) before income taxes	$(483)	$—	$(483)	$1,885	$—	$1,885
Income tax provision (benefit) [1]			(530)			394
Net income			47			1,491
Preferred stock dividend requirement [1]			10			10
Income Available for Common Stock			$37			$1,481

[1] These items impacted earnings for the nine months ended September 30, 2018 and 2017.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility’s operating results for the three and nine months ended September 30, 2018 and 2017, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility’s electric and natural gas operating revenues that impacted earnings increased by $50 million, or 2%, in the three months ended September 30, 2018, compared to the same period in 2017, primarily due to increased base revenues authorized in the 2017 GRC.

The Utility's electric and natural gas operating revenues that impacted earnings decreased by $15 million in the nine months ended September 30, 2018, compared to the same period in 2017, primarily due to $102 million in retroactive base revenues authorized in the 2015 GT&S rate case recognized in the nine months ended September 30, 2017, partially offset by an increase in base revenues as authorized in the 2017 GRC in the same period in 2018.

Operating and Maintenance

The Utility’s operating and maintenance expenses that impacted earnings increased by $120 million, or 11%, in the three months ended September 30, 2018, compared to the same period in 2017, primarily due to Northern California wildfire-related legal and other costs of $53 million in the three months ended September 30, 2018, with no similar charges in the same period in 2017. Additionally, the Utility incurred approximately $50 million in costs related to higher premiums for liability insurance (net of the portion deferred as a regulatory asset for amounts that are probable of recovery), during the three months ended September 30, 2018, as compared to the same period in 2017. These increases were partially offset by a $38 million reduction to the estimated disallowance for gas-related capital costs that were expected to exceed authorized amounts in the three months ended September 30, 2018, with no corresponding activity during the same period in 2017.

The Utility’s operating and maintenance expenses that impacted earnings increased by $148 million, or 4%, in the nine months ended September 30, 2018, compared to the same period in 2017, primarily due to Northern California wildfire-related legal and other costs of $120 million and clean-up and repair costs of $40 million, and an increase in environmental remediation expenses at the San Francisco Potrero Power Plant of approximately $40 million in the nine months ended September 30, 2018, with no corresponding charges during the same period in 2017. Additionally, the Utility incurred approximately $50 million in costs related to higher premiums for liability insurance (net of the portion deferred as a regulatory asset for amounts that are probable of recovery), during the nine months ended September 30, 2018, as compared to the same period in 2017. These increases were partially offset by a $38 million reduction to the estimated disallowance for gas-related capital costs that were expected to exceed authorized amounts in the nine months ended September 30, 2018. Additionally, the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement in the nine months ended September 30, 2017, with no similar charges in the same period in 2018.

Wildfire-related claims, net of insurance recoveries

Costs related to wildfires that impacted earnings decreased by $63 million in the three months ended September 30, 2018, compared to the same period in 2017. In 2017, the Utility recognized a $350 million charge, offset by probable insurance recoveries of $297 million related to the Butte fire, compared to $10 million of probable insurance recoveries associated with the Northern California wildfires recorded in 2018.

Costs related to wildfires that impacted earnings increased by $2.1 billion in the nine months ended September 30, 2018, compared to the same period in 2017 primarily due to a pre-tax charge of $2.5 billion, offset by probable insurance recoveries of $385 million associated with the Northern California wildfires in 2018, compared to a $350 million charge offset by probable insurance recoveries of $350 million related to the Butte fire in the same period in 2017.

The Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by additional potential losses resulting from the impact of the Northern California wildfires and any additional charges associated with costs related to the Butte fire. (See “Item 1A. Risk Factors” in the 2017 Form 10-K and in Part II below under “Item 1A. Risk Factors,” as well as Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q.)

Depreciation, Amortization, and Decommissioning

The Utility’s depreciation, amortization, and decommissioning expenses that impacted earnings increased by $49 million, or 7%, and $123 million, or 6%, in the three and nine months ended September 30, 2018, respectively, compared to the same periods in 2017, primarily due to capital additions.

Interest Income and Interest Expense

There were no material changes to interest income and interest expense that impacted earnings for the periods presented.

Other Income, Net

There were no material changes to other income, net, that impacted earnings for the periods presented.

Income Tax Provision

The income tax provision decreased by $124 million in the three months ended September 30, 2018, as compared to the same period in 2017. The effective tax rates for the three months ended September 30, 2018 and 2017 were 2.5% and 21.2%, respectively. The decrease in the income tax provisions and in the effective tax rates were primarily the result of a decrease in the corporate income tax rate from 35% to 21% as a result of the Tax Act.

The income tax provision decreased by $924 million in the nine months ended September 30, 2018, as compared to the same period in 2017. The effective tax rates for the nine months ended September 30, 2018 and 2017 were 109.8% and 20.9%, respectively. The decrease in the income tax provisions and increases in the effective tax rate were primarily the result of pre-tax losses in 2018 versus pre-tax income in 2017, partially offset by a decrease in the corporate income tax rate from 35% to 21% as a result of the Tax Act.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Federal statutory income tax rate	21.0 %	35.0 %	21.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:				
State income tax (net of federal benefit) (1)	2.1 %	2.6 %	22.8 %	2.4 %
Effect of regulatory treatment of fixed asset differences (2)	(15.9)%	(13.0)%	56.4 %	(12.9)%
Tax credits	(0.5)%	(0.5)%	1.9 %	(1.1)%
Other, net	(4.2)%	(2.9)%	7.7 %	(2.5)%
Effective tax rate	2.5 %	21.2 %	109.8%	20.9 %

(1) Includes the effect of state flow-through ratemaking treatment.
(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision (impacting the three and nine months ended September 30, 2017) and the 2017 GRC decision (impacting the three and nine months ended September 30, 2018), and by the 2015 GT&S decision (impacting the three and nine months ended September 30, 2017, and 2018, respectively). All amounts are impacted by the level of income before income taxes. The 2014 GRC, 2017 GRC, and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. The amounts for the three and nine months ended September 30, 2018 also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

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 in Item 1.) The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Cost of purchased power	$1,174	$1,392	$2,846	$3,255
Fuel used in own generation facilities	82	74	192	181
Total cost of electricity	$1,256	$1,466	$3,038	$3,436
Average cost of purchased power per kWh (1)	$0.252	$0.151	$0.157	$0.126
Total purchased power (in millions of kWh) (2)	4,658	9,189	18,101	25,905

(1) Average cost of purchased power was impacted primarily by lower Utility electric customer demand, driven by customer departures to CCAs or direct access providers, and a larger percentage of higher cost renewable energy resources being allocated to the fewer remaining Utility electric customers and by increased CAISO market volatility. See further discussion in "Legislative and Regulatory Initiatives - Power Charge Indifference Adjustment," below.
(2) The decrease in purchased power for the three and nine months ended September 30, 2018 compared to the same periods in 2017 was primarily due to lower Utility electric customer demand and by increased CAISO market volatility in the three months ended September 30, 2018.

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 in Item 1.) 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 September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Cost of natural gas sold	$45	$50	$355	$436
Transportation cost of natural gas sold	24	28	82	88
Total cost of natural gas	$69	$78	$437	$524
Average cost per Mcf (1) of natural gas sold	$1.55	$1.85	$2.25	$2.71
Total natural gas sold (in millions of Mcf)	29	27	158	161

(1) One thousand cubic feet

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings.

Other Income, Net

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

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations, finance capital expenditures, make scheduled principal and interest payments, 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 declare 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's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, and issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters, including the outcome of the uncertainties and potential liabilities associated with the Northern California wildfires. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. During 2018, PG&E Corporation's and the Utility's credit ratings were subject to multiple downgrades by Fitch Ratings, S&P Global Ratings, and Moody's Investors Service, Inc. At September 30, 2018, PG&E Corporation's and the Utility's credit ratings remained at investment grade levels. If S&P Global Ratings and Moody's Investors Service, Inc. downgraded the Utility below investment grade, the Utility estimates it would be required to fully collateralize up to $800 million in net liability positions. (See Note 7 and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

PG&E Corporation's and the Utility's equity needs could increase materially and its liquidity and cash flows could be materially affected by potential costs and other liabilities in connection with the Northern California wildfires. The Utility's equity needs will continue to be affected by the timing and amount of disallowed capital expenditures, and by fines, penalties and claims that may be imposed in connection with the matters described in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, "Part II. Other Information, Item 1. Legal Proceedings," and in the 2017 Form 10-K. In addition, PG&E Corporation's and the Utility's ability to access the capital markets in a manner consistent with its past practices, if at all, could be adversely affected by such matters. (See "Item 1A. Risk Factors" in the 2017 Form 10-K and in Part II below under "Item 1A. Risk Factors".)

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

Short-term Borrowing Authorization Application

On October 9, 2018, the Utility filed an application with the CPUC to increase its authority to finance short-term borrowing needs and procurement-related collateral costs. This application requests that the CPUC increase the authorized amount by $2 billion to an aggregate amount not to exceed $6 billion. The Utility's existing $4 billion short-term debt authorization remains in place while the CPUC reviews the new application. The increased authority will provide flexibility for the Utility to meet potentially higher collateral posting requirements associated with the Utility’s energy procurement activities and to provide flexibility and liquidity to fund short-term capital requirements and general working capital requirements. The Utility has requested that the CPUC give this application expedited consideration but is unable to predict the timing and outcome of this proceeding.

Debt and Equity Financings

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the nine months ended September 30, 2018. As of September 30, 2018, the remaining amount available under this agreement was $246.3 million.

During the nine months ended September 30, 2018, PG&E Corporation issued 3.6 million shares for cash proceeds of $136.7 million under the PG&E Corporation 401(k) plan and share-based compensation plans. The proceeds from these sales were used for general corporate purposes.

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

In February 2018, the Utility's $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. Additionally, in February 2018, the Utility entered into a $250 million floating rate unsecured term loan that will mature on February 22, 2019. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. The term loan will mature on April 16, 2020, unless extended by PG&E Corporation pursuant to the terms of the term loan agreement. The proceeds were used for general corporate purposes, including the early redemption of PG&E Corporation's outstanding $350 million principal amount of 2.40% Senior Notes due March 1, 2019. On April 26, 2018, PG&E Corporation completed the early redemption of these bonds, which satisfied and discharged its remaining obligation of $350 million.

In August 2018, the Utility issued $500 million principal amount of 4.25% senior notes due August 1, 2023 and $300 million principal amount of 4.65% senior notes due August 1, 2028. The proceeds will be used to repay $500 million floating rate Senior Notes due November 28, 2018, to repay $250 million term loan maturing on February 22, 2019 and for general corporate purposes.

Revolving Credit Facilities and Commercial Paper Programs

At September 30, 2018, PG&E Corporation and the Utility had $300 million and $2.9 billion available under their respective $300 million and $3.0 billion revolving credit facilities. During the quarter ended September 30, 2018, PG&E Corporation and the Utility repaid in full borrowings under their respective revolving credit facilities of $50 million and $650 million, respectively. At September 30, 2018, PG&E Corporation and the Utility did not have any borrowings outstanding under their respective revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

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 nine months ended September 30, 2018, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $39 million and $11 million, respectively, and a maximum outstanding balance of $137 million and $205 million, respectively. At September 30, 2018, PG&E Corporation and the Utility did not have any outstanding commercial paper.

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 September 30, 2018, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 49.9% 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 September 30, 2018, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

Utility Cash Flows

The Utility's cash flows were as follows:

	Nine Months Ended September 30,	
(in millions)	2018	2017
Net cash provided by operating activities	$4,184	$4,692
Net cash used in investing activities	(4,617)	(3,950)
Net cash provided by (used in) financing activities	357	(743)
Net change in cash and cash equivalents	$(76)	$(1)

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During the nine months ended September 30, 2018, net cash provided by operating activities decreased by $508 million compared to the same period in 2017. This decrease was due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections and vendor billings and payments.

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

- the timing and amount of costs in connection with the Northern California wildfires (and the timing and amount of related insurance recoveries), as well as additional potential liabilities in connection with third-party claims and fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with current and future enforcement, litigation, and regulatory matters (see "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part II, Item 1. Legal Proceedings for more information);

- the timing and amount of premium payments related to wildfire insurance (see "Wildfire Insurance" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 for more information);

- the Tax Act, which is expected to accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows (see "Overview" above and "Regulatory Matters" below for more information);

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

- the timing and amount of substantially increasing costs in connection with fire hazard prevention work (see "Overview" above and "Regulatory Matters" below for more information); and

- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

Investing Activities

Net cash used in investing activities increased by $667 million during the nine months ended September 30, 2018 as compared to the same period in 2017 primarily due to an increase in capital expenditures. The Utility's investing activities primarily consist of the construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's capital expenditures were approximately $5.7 billion in 2017. Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $6.5 billion in capital expenditures in 2018, and $6.4 billion in 2019.

Financing Activities

Net cash provided by financing activities increased by $1.1 billion during the nine months ended September 30, 2018 as compared to the same period in 2017. This increase was primarily due to the suspension of dividend payments (see "Dividends" section above) and a reduction in net repayments of commercial paper of approximately $600 million.

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 in Item 1. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2017 Form 10-K and "Part II. Other Information, Item 1. Legal Proceedings."

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of the proceedings described below and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Discussed below are significant regulatory developments that have occurred since filing the 2017 Form 10-K.

2017 General Rate Case

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

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

Also, as a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2017 GRC. The PFM, if adopted, would reduce revenue requirements by $267 million and $296 million for 2018 and 2019 respectively, and increase rate base by $199 million and $425 million for 2018 and 2019, respectively. The Utility cannot predict the timing and outcome of this PFM.

Finally, the CPUC continues its review of the Utility's update of the cost effectiveness study for the SmartMeter™ Upgrade project. The Utility provided an update of the cost effectiveness study for the SmartMeter™ Upgrade project to the CPUC on July 10, 2017. On August 9, 2018, the CPUC extended the statutory deadline for the 2017 GRC to February 9, 2019, in order to allow for comments and CPUC action on any PD on the SmartMeter™ upgrade cost effectiveness study. The Utility cannot predict the timing and outcome of any CPUC action in connection with this study and its impact on the 2017 GRC revenue requirement and rate base.

For more information, see the 2017 Form 10-K.

Risk Assessment Mitigation Phase Filing

On November 30, 2017, the Utility filed its first RAMP report with the CPUC in advance of its 2020 GRC application. The RAMP is a new CPUC requirement directing each large investor-owned energy utility to submit a report describing how it assesses its risks and how it plans to mitigate and minimize such risks in advance of the utility's GRC application. The Utility's RAMP report informed the CPUC of the Utility's top safety-related risks, risk assessment procedures, and proposed mitigations of those risks for 2020-2022.

On April 3, 2018, the SED released a report assessing the Utility's RAMP report. The SED report requested, among other items, an updated risk analysis regarding wildfire risk mitigation strategies in the Utility's 2020 GRC. A workshop on the report was held on April 17, 2018, and the parties submitted opening and reply comments on May 10, 2018, and May 24, 2018, respectively. The RAMP results will be incorporated in the Utility's 2020 GRC.

2020 General Rate Case

On June 4, 2018, the Utility submitted a letter to the CPUC requesting an extension of up to four months, from September 1, 2018, to January 1, 2019, to file its 2020 GRC application. The Utility requested this extension due to extraordinary uncertainties related to the 2017 Northern California wildfires that could significantly impact the content of the rate case application. On June 29, 2018, the CPUC granted the Utility's extension request to file its 2020 GRC application no later than January 1, 2019. On October 15, 2018, the Utility notified the CPUC that the Utility anticipates submitting its 2020 GRC to the CPUC between December 10, 2018 and December 20, 2018.

2015 Gas Transmission and Storage Rate Case

In its final decisions in the Utility's 2015 GT&S rate case, the CPUC excluded from rate base $696 million of capital spending in 2011 through 2014. This was the amount recorded in excess of the amount adopted in the 2011 GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The Utility would be required to take a charge in the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance. The audit is still in process. The decision established new one-way balancing accounts to track certain costs, as well as various cost caps that will increase the risk of disallowance over the current rate case cycle.

As a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2015 GT&S rate case proposing to reduce revenue requirements by $58 million and increase rate base by $12 million for 2018 (excluding the impacts of an approximately $7 million increase in revenue requirement and a $60 million increase in rate base associated with the Utility's private letter ruling advice letter approved by the CPUC on July 18, 2018). The Utility cannot predict the timing and outcome of this PFM.

In August 2016 and January 2017, TURN, Cal PA and Indicated Shippers filed applications for rehearing of the CPUC decisions in the Utility's 2015 GT&S rate case. The Utility cannot predict whether the CPUC will grant the applications for rehearing or adopt the parties’ recommendations.

For more information, see the 2017 Form 10-K.

2019 Gas Transmission and Storage Rate Case

On November 17, 2017, the Utility filed its 2019 GT&S rate case application with the CPUC for the years 2019 through 2021. While the Utility has not formally proposed a fourth year for this rate case, it provided a revenue requirement and rates for 2022, in the event the CPUC adopts an additional year. On October 1, 2018, the Utility entered into a stipulation with Cal PA that, if approved, would extend the rate case cycle through 2022 as recommended by Cal PA.

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

The requested rate base for 2019 is $4.66 billion, which corresponds to an increase of $0.95 billion over the 2018 authorized rate base of $3.71 billion. These rate base amounts exclude approximately $576 million of capital spending subject to audit by the CPUC related to 2011 through 2014 expenditures in excess of amounts adopted in the 2011 GT&S rate case. The Utility is unable to predict whether the $576 million, or a portion thereof, will ultimately be authorized by the CPUC and included in the Utility’s future rate base. The Utility’s request also excludes rate base adjustments that the Utility requested with the CPUC on November 14, 2017, resulting from the Internal Revenue Service’s October 5, 2017 private letter ruling issued in connection with the CPUC’s final phase two decision in the 2015 GT&S rate case. The Utility’s request is based on capital expenditure forecasts of $971 million for 2019, $963 million for 2020, and $804 million for 2021 (which exclude common capital allocations).

The requested increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations issued by DOGGR, the Pipeline and Hazardous Materials Safety Administration, and the CPUC.

As a result of the Tax Act, on March 30, 2018, the Utility submitted updated testimony to the CPUC. The updated testimony, including the private letter ruling advice letter, reduces the Utility's previously forecasted revenue requirement by $25 million for 2019, $30 million for 2020, $22 million for 2021, and $5 million for 2022, and increases rate base by $188 million for 2019, $254 million for 2020, $378 million for 2021, and $469 million for 2022.

In testimony submitted to the CPUC on June 29, 2018, Cal PA recommended a 2019 revenue requirement of $1.35 billion, an increase of $45 million over 2018 adopted amounts. All other parties filed testimony on July 20, 2018. TURN proposed widespread reductions in forecast costs and recommended capital and expense disallowances of more than $500 million associated with either work completed at a cost greater than adopted in the 2015 GT&S rate case or work that was approved in the 2015 GT&S rate case and is being requested again in the 2019 GT&S rate case. One other party, Indicated Shippers, made proposals for significant capital and expense reductions in the forecast related to transmission pipe and storage.

Evidentiary hearings concluded on October 12, 2018. The Utility will file opening briefs on November 14, 2018 and reply briefs on December 14, 2018. A later phase of the proceeding will address the reasonableness of certain recorded capital expenditures associated with Line 407, as required by the 2015 GT&S rate case decision. The later phase will also address the removal of officer compensation costs from the revenue requirement, which is required by the passage of SB 901. (See “Legislative and Regulatory Initiatives” below.)

For more information, see the 2017 Form 10-K.

Transmission Owner Rate Cases

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

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

On February 28, 2018, the Utility filed a motion to establish procedures on remand requesting a hearing and additional briefing on the issues identified in the Ninth Circuit Court's opinion. On August 20, 2018, FERC issued an order granting the Utility's motion to allow for additional briefing. The order also consolidated the TO18 rate case with TO16 and TO17 for this issue. The Utility filed briefs on September 19, 2018 and reply briefs on October 10, 2018. The Utility is unable to predict the timing and outcome of FERC’s decision.

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

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

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

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case proposing an ROE of 9.13% compared to the Utility’s request of 10.90%, and an estimated composite depreciation rate of 2.96% compared to the Utility’s request of 3.25%. The ALJ also rejected the Utility's method of allocating common plant between CPUC and FERC jurisdiction. In addition, the ALJ proposed to reduce forecasted capital and expense spending to actual costs incurred for the rate case period. Further, the ALJ proposed to remove certain items from the Utility's rate base and revenue requirement. The Utility and intervenors filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. The Utility expects FERC to issue a final decision in mid-2019.

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

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

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

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

On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with TO19. As part of the settlement,
the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined in the TO18 final decision. Additionally, if FERC determines that the Utility is not entitled to the 50 basis point incentive adder for the Utility's continued CAISO participation, than the Utility would be obligated to make a refund to customers of approximately $25 million.

For more information on the TO rate cases, see the 2017 Form 10-K.

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

On October 1, 2018, the Utility filed its TO20 rate case at FERC requesting approval of a formula rate for the costs associated with the Utility's electric transmission facilities. The formula rate would replace the "stated rate" methodology that the Utility used in its previous TO rate case filings. If approved, the formula rate methodology would still include an authorized revenue requirement and rate base for a given year, but it would also provide for an annual update of the following year's revenue requirement and rates in accordance with the terms of the FERC-approved formula. Under the formula rate mechanism, transmission revenues, including CWIP, will be updated to the actual cost of service annually. Differences between amounts collected and determined under the formula rate will be either collected from or refunded to customers.
In the filing, the Utility forecasts a 2019 retail electric transmission revenue requirement of $1.96 billion. The proposed amount reflects an approximately 9.5% increase over the as-filed TO19 requested revenue requirement of $1.79 billion (a subsequent reduction to $1.66 billion was identified as a result of the Tax Act). The Utility forecasts that it will make investments of approximately $1.1 billion and $0.7 billion for 2018 and 2019, respectively, for various capital projects to be placed in service before the end of 2019. Including projects to be placed in service beyond 2019, the Utility forecasts total electric transmission capital expenditures of $1.4 billion in 2018 and $1.4 billion in 2019. The Utility's forecasted rate base for 2019 is approximately $8 billion on a weighted average basis, compared to the Utility's forecasted rate base of $6.9 billion in 2018. The Utility has requested that FERC approve a 12.5% return on equity (which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO), an increase from the 10.75% (also including a 50 basis point CAISO incentive adder) requested in its TO19 rate case.
The Utility requested that FERC accept its formula rate filing to become effective on December 1, 2018, and suspend the use of the new rates until January 1, 2019, to facilitate a calendar year true-up period corresponding to the Utility’s FERC Form 1 reporting. As a result, under the Utility’s formula rate, the rates in effect from TO19 would continue to be used until January 1, 2019. FERC may decide to suspend the TO20 rates for a longer period of time, up to a maximum of five months from the effective date. If FERC adopts the maximum five-month suspension, TO20 rates would go into effect on May 1, 2019. In the event of a delay in the effective date of TO20 rates, the first true-up mechanism would be applied to the period beginning on the effective date through the end of 2019.

The Utility cannot predict the timing and outcome of FERC’s response. Following FERC’s acceptance of the Utility’s formula rate request, the Utility expects to file an annual update to its TO tariff on or before December 1 of each year beginning in 2019, for rates and charges to become effective January 1 of the following year, consistent with the formula rate.

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 (together, the “Joint Parties”).

On January 11, 2018, the CPUC issued a final decision in the Utility's proposal to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. The CPUC also:

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

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

On October 16, 2018, in response to SB 1090, the CPUC issued a proposed decision addressing the key remaining goals of the Diablo Canyon joint proposal agreement, including:

- approving the community impact mitigation settlement of $85 million, originally proposed in the joint settlement agreement;
- deferring implementation to its Integrated Resource Planning to ensure that there is no increase in GHG emissions as a result of the Diablo Canyon retirement; and
- approving full funding of the $352.1 million Diablo Canyon employee retention program, originally proposed in the joint settlement agreement.

California State Lands Commission Lands Lease

On June 28, 2016, the 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 intends to 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, as well as alleging that the State Lands Commission should be required to perform an environmental review of the new lands lease. On July 11, 2017, in Los Angeles Superior Court, 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. The World Business Academy appealed this decision. On June 13, 2018, the California Court of Appeals affirmed the Superior Court ruling. On August 29, 2018, the California Supreme Court denied a petition for review filed by the World Business Academy, rendering the California State Lands Commission's approval of the new lands lease for Diablo Canyon final and non-appealable.

Asset Retirement Obligations

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

While the adopted 2015 NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program, which were approved in the CPUC's final decision and in SB 1090. The employee retraining program costs will be included in the 2018 NDCTP forecast. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study, along with the NDCTP application, to the CPUC by the end of December 2018.

The Utility expects to file its 2018 NDCTP application in December 2018. For more information, see "Asset Retirement Obligations" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Wildfire Expense Memorandum Account

On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA for the purpose of tracking specific incremental wildfire liability costs effective as of July 26, 2017. In the WEMA, the Utility can record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been forecasted and adopted in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) insurance premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, or through FERC authorized rates, will be credited to the WEMA as they are received. The WEMA will not include the Utility's costs for fire response and infrastructure costs which are tracked in the CEMA. The decision does not grant the Utility rate recovery of any wildfire related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. (See Notes 3 and 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

Catastrophic Event Memorandum Account Applications

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities through a CEMA. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work are tracked in the CEMA. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC approval.

2016 CEMA Application

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

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as $405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. Also, the 2018 CEMA application originally sought cost recovery of $555 million on a forecast basis, subject to true-up if actual costs were greater or less than the forecast, for additional tree mortality and fire risk mitigation work anticipated in 2018 and 2019. On October 12, 2018, the Utility notified the CPUC and other parties that $180 million of the forecasted 2018 and 2019 fire risk mitigation costs would be removed from

CEMA and instead pursued in the FHPMA. Upon removal of the $180 million, the Utility's forecast of costs for 2018 and 2019 sought in the application would be approximately $375 million.

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

A prehearing conference was held on July 10, 2018, which covered issues related to schedule, scope of costs, interim rate relief, and the engagement of an independent auditor to review tree mortality mitigation costs. On July 25, 2018, the Utility filed a motion for interim rate relief, to authorize collection in rates beginning January 1, 2019, for $441 million of costs incurred in 2016 and 2017 related to storm and wildfire response and mandated tree mortality work. On August 10, 2018, the CPUC issued a scoping memo and procedural schedule. As directed in the scoping memo, opening and reply briefs on the Utility's request related to recovery of costs on a forecast basis were filed on August 31, 2018, and September 14, 2018, respectively. On November 2, 2018, the assigned ALJ denied the Utility's request for interim rate relief.

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

Fire Hazard Prevention Memorandum Account

The CPUC allows utilities to track and record costs associated with the implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead powerline facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. The Utility currently is authorized to track such costs in the FHPMA through the end of 2019. During the nine months ended September 30, 2018, the Utility has recorded $76 million of costs to the FHPMA, corresponding to vegetation management work performed to comply with CPUC December 2017 fire safety regulations. While the Utility believes such costs are recoverable, rate recovery requires CPUC authorization in a separate proceeding or through a GRC. (See Note 3 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

Other Regulatory Proceedings

Transportation Electrification

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

On January 20, 2017, the Utility filed its TE application with the CPUC requesting program funding over five years (2018-2022) related to make-ready infrastructure for TE in medium to heavy-duty vehicle sectors, fast charging stations, and short-term projects that includes a series of TE demonstration projects and pilot programs.

On January 11, 2018, the CPUC approved, with modifications, four of the five short-term projects proposed by the Utility for a total of approximately $8 million.

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

Electric Distribution Resources Plan

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

The CPUC issued a decision on February 15, 2018, requiring the California IOUs to use the CEC’s DER forecast for the 2018-2019 distribution planning cycle. The decision also requires the IOUs to develop an alternative planning forecast scenario in 2018 to better inform DER sourcing policies by establishing a method for calculating costs and benefits for DER grid integration. Historically, the Utility has planned using the CEC forecast and will have the opportunity to adjust forecasts for EV, photovoltaic, and energy storage, if needed during the planning cycle.

The CPUC's decision also requires the Utility to develop and submit annually a grid needs assessment and distribution deferral opportunity report to identify proposed electric distribution investments that could be deferred by deploying DERs. The decision also extends the 4% pre-tax regulatory incentive mechanism, being piloted in the Integrated Distributed Energy Resources (IDER) proceeding, to all DER distribution deferral projects. The Utility filed its first grid needs assessment with the CPUC on June 1, 2018, and its first distribution deferral opportunity report on September 4, 2018. The Utility has convened a distribution planning advisory group, comprised of CPUC staff, ratepayer and environmental advocates, DER market participants, and Utility staff, to review the Utility's grid needs assessment, distribution deferral opportunity report, and potential distribution deferral locations where DER solutions or non-wire alternatives can be considered for competitive solicitations.

On March 26, 2018, the CPUC issued a final decision requiring the Utility to include a grid modernization plan in the Utility's GRC to address distribution system upgrades required to deploy DERs. The grid modernization plan must include a narrative 10-year vision for investments needed to support DER growth, safety, and reliability, and a status update of previously funded DER-related grid modernization GRC projects. On June 25, 2018, the Utility hosted a grid modernization workshop to provide a high-level overview of its grid integration platform and 10-year plan. The Utility is required to submit a grid modernization plan with each GRC application starting with its 2020 GRC application.

LEGISLATIVE AND REGULATORY INITIATIVES

Senate Bill 901

On September 21, 2018, California's governor signed legislation to strengthen California's ability to prevent and recover from catastrophic wildfires, including SB 901. Some of the significant highlights of SB 901 include:

- imposing more restrictive forest management practices and providing support and incentives to facilitate that work;
- providing factors that the CPUC should consider when it conducts a review of the reasonableness of costs and expenses arising from a catastrophic wildfire occurring on or after January 1, 2019;
- in applications for cost recovery in connection with the 2017 wildfires, directing the CPUC to consider the electric corporation's financial status and determine the maximum amount a utility can pay without harming customers or materially impacting its ability to provide adequate and safe service, and ensuring that the costs or expenses that are disallowed for recovery in rates assessed for the wildfires, in the aggregate, do not exceed that amount;
- authorizing the CPUC to issue a financing order that permits recovery, through issuance of recovery bonds (securitization), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 wildfires, any amounts in excess of the maximum disallowance (see above). Securitization is available, for prudently incurred costs, for the 2017 wildfires and catastrophic wildfires occurring on or after January 1, 2019;
- requiring electric corporations to prepare and submit to the CPUC a wildfire mitigation plan. Among other things, the plan will include a description of the preventive strategies and programs of electric corporations that are designed to minimize the risk of their electrical lines and equipment causing catastrophic wildfires and protocols related to plan activities. Failure to substantially comply with such plan will result in penalties. The CPUC will consider whether the

cost of implementing the plan is just and reasonable in each electric corporation's GRC;

- establishing a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures; and
- prohibiting an electric or gas corporation from recovering expenses for any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of such utility from customers.

On October 25, 2018, the CPUC opened an OIR to implement the wildfire mitigation plan provisions in SB 901. This OIR will only focus on the wildfire mitigation plan of SB 901 implementation, and will not address utility cost recovery. Cost recovery associated with SB 901 wildfire mitigation plans will be addressed in utilities' GRCs.

Power Charge Indifference Adjustment

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

- adopting benchmark values used to set the PCIA rate that more closely resemble actual market prices for resource adequacy and renewable energy credits;
- allowing legacy utility-owned generation costs to be recovered from CCA customers;
- eliminating the 10-year limit on PCIA cost recovery for post-2002 utility owned generation and certain storage costs; and
- adding an annual true-up to the PCIA rate based on market sales for brown power, with further discussion in phase 2 of the PCIA proceeding regarding true-up of resource adequacy, and renewable energy credits.

CCA and DA customers will pay a revised PCIA rate starting January 1, 2019. The CPUC also ordered a phase 2 of the PCIA proceeding to develop structures, processes, and rules to govern utility portfolio optimization and management in the future.

OIR to Consider Strategies and Guidance for Climate Change Adaptation

On April 26, 2018, the CPUC opened an OIR to consider strategies for integrating climate change adaptation matters into relevant CPUC proceedings. Phase one will focus on how to integrate climate change adaptation into the IOUs' existing planning and operations to ensure utility safety and reliability.

The CPUC OIR will consider:

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

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

For information related to the Utility's climate change resiliency strategies see Item 1 in the 2017 Form 10-K.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q, as well as "Item 1A. Risk Factors" and Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.)

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 in Item 1). 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 MD&A "Contractual Commitments" in Item 7 of the 2017 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 Item 8 of the 2017 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 risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for 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 2017 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the nine months ended September 30, 2018.

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, AROs, and pension and other post-retirement 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 2017 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 in Item 1.

FORWARD-LOOKING STATEMENTS

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

- the impact of the Northern California wildfires, including whether the Utility will be able to timely recover costs incurred in connection with the Northern California wildfires in excess of the Utility's currently authorized revenue requirements; the timing and outcome of the remaining wildfire investigations and the extent to which the Utility will have liability associated with these fires; the timing and amount of insurance recoveries; and potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency were to bring an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;

- the timing and outcome of the Butte fire litigation, the timing and outcome of any proceeding to recover costs in excess of insurance through rates; the effect, if any, that the SED's $8.3 million citations issued in connection with the Butte fire may have on the 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;

- whether PG&E Corporation and the Utility are able to successfully challenge the application of the doctrine of inverse condemnation to the Northern California wildfires and the Butte fire;

- the timing and outcome of future regulatory and legislative developments in connection with SB 901, including the customer harm threshold in connection with the Northern California wildfires, future wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures;

- the outcome of the Utility's community wildfire safety program that the Utility has developed in coordination with first responders, civic and community leaders, and customers, to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather; and the cost of the program, and the timing and outcome of any proceeding to recover such cost through rates;

- 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 timing and outcome of CPUC decision(s) related to the Utility's March 2018 submissions to the CPUC and May 2018 submission to the FERC in connection with the impact of the Tax Act on the Utility's rate cases and its implementation plan;

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

- the outcome of the probation and the monitorship imposed by the federal court after the Utility's conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, potential reliability penalties or sanctions from the North American Electric Reliability Corporation, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas- and electric- related laws and regulations, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

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

- the outcome of the safety culture OII, including its phase two PD issued on October 25, 2018, and future legislative or regulatory actions that may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or implement corporate governance changes;

- whether the Utility can control its costs within the authorized levels of spending, and timely recover its costs through rates; whether the Utility can continue implementing a streamlined organizational structure and achieve project savings, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

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

- the timing and outcome of the October 1, 2018 request for rehearing of FERC's denial of the complaint filed by the CPUC and certain other parties that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO’s Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC’s decision granting the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;

- the outcome of current and future self-reports, investigations, or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility’s compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion, or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cybersecurity, environmental laws and regulations; and the outcome of existing and future SED notices of violations;

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

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility’s known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

- the impact of SB 100, which was signed into law on September 10, 2018, that increases the percentage from 50 percent to 60 percent of California’s electricity portfolio that must come from renewables by 2030; and the requirement that 100 percent of all retail electricity sales must come from RPS-eligible or carbon-free resources by 2045;

- how the CPUC and the California Air Resources Board implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;

- the impact of the California governor's executive order issued on January 26, 2018, to implement a new target of five million zero-emission vehicles on the road in California by 2030;
- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility’s natural gas compressor station site located near Hinkley, California and the Utility's fossil fuel-fired generation sites;
- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of potential actions, such as legislation, taken by state agencies that may affect the Utility’s ability to continue operating Diablo Canyon until its planned retirement;

- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;

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

- the breakdown or failure of equipment that can cause damages, including fires, and unplanned outages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Utility's procurement service for CCAs;

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

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could, among other things, result in cash collateral postings, higher borrowing costs and fewer financing options, especially if PG&E Corporation or the Utility were to lose their investment grade credit ratings;

- the impact of the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the uncertainty in connection with the Northern California wildfires, the ultimate outcomes of the CPUC's pending investigations, and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation, and whether they will continue impacting PG&E Corporation's and the Utility's ability to pay dividends;

- 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;

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changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the current federal administration; and

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

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 2017 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. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab and links to certain documents and information related to the Northern California wildfires and the Butte fire which may be of interest to investors, at http://investor.pgecorp.com, under the "Wildfire Updates" tab, in order to publicly disseminate such information. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link.

ITEM 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 MD&A and in Note 7: Derivatives and Note 8: Fair Value Measurements of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of September 30, 2018, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 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 September 30, 2018, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part I, MD&A: "Enforcement and Litigation Matters."

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

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The 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 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 that 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 potential reduction of the Utility's return on equity until any recommendations adopted by the CPUC are implemented.

On November 17, 2017, the CPUC issued a phase two scoping memo and procedural schedule. The scoping memo directed the Utility to file testimony addressing a number of issues including: adoption of the safety recommendations from the consultant, the Utility's implementation process for the safety recommendations of the consultant, the Utility's Board of Director's actions and initiatives related to safety culture and the consultant's recommendations, the Utility's corrective action program, and the Utility's response to certain specified safety incidents that occurred in 2013 through 2015.

The CPUC retained the same consultant to prepare a second report on the Utility's safety culture and governance with respect to the Utility's implementation plan in response to the consultant's recommendations. The consultant's report is expected to be completed by the end of November 2018.

On October 25, 2018, the assigned ALJ issued a PD in connection with this proceeding. If adopted, the Utility would be required to implement the recommendations set forth in the May 2017 consultant report no later than July 1, 2019, and to submit quarterly reports on the status of their implementation beginning in the fourth quarter of 2018. The PD, if adopted, would not result in the adoption of safety performance metrics and targets at this time, but they could be considered in the future. Additionally, the PD directs the assigned CPUC commissioner and the ALJ to develop a process for a remedial phase and to issue a scoping memo.

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

The earliest the CPUC could vote on this PD is November 29, 2018.

Diablo Canyon Nuclear Power Plant

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board, the Utility, and the California Attorney General's Office, see Part I, Item 3. "Legal Proceedings" in the 2017 Form 10-K.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, see the section of the 2017 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Forward-Looking Statements."

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the multiple wildfires that spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City, beginning on October 8, 2017 (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires resulted in 44 fatalities.

Cal Fire issued its determination on the causes of 17 of the Northern California wildfires, and alleged that each of these fires involved the Utility's equipment. The remaining wildfires remain under Cal Fire's investigation, including the possible role of the Utility's power lines and other facilities. Additionally, the Northern California wildfires are under investigation by the CPUC's SED.

In connection with the Northern California wildfires, if the doctrine of inverse condemnation applies, the Utility could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows" in PG&E Corporation and the Utility's 2017 Form 10-K, Item 1A, Risk Factors.) In addition to such claims for property damage, interest, and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action, including as a result of the referral by Cal Fire of certain investigation reports to the appropriate county District Attorney's offices, and determined that the Utility failed to comply with applicable laws and regulations.

On September 6, 2018, the California Department of Insurance issued a news release announcing an update on property losses in connection with the October and December 2017 wildfires in California. As of that date, insurers have received nearly 55,000 insurance claims totaling more than $12.28 billion in losses, of which approximately $10 billion relates to statewide claims from the Northern California wildfires. The balance relates to claims from the Southern California December 2017 wildfires. That news release reflected insured property losses only. Also, that amount did not account for uninsured losses, interest, attorneys' fees, fire suppression and clean-up costs, personal injury and wrongful death damages or other costs. If PG&E Corporation and the Utility were to be found liable for certain or all of such other costs and expenses, including the potential liabilities outlined above, the amount of the liability could significantly exceed the approximately $10 billion in estimated insured property losses with respect to the Northern California wildfires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected.

PG&E Corporation and the Utility also are the subject of a still increasing number of lawsuits that have been filed against PG&E Corporation and the Utility in Sonoma, Napa and San Francisco Counties' Superior Courts, several of which seek to be certified as class actions, asserting damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, two insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed 36 subrogation complaints in the San Francisco County Superior Court. Further, several derivative lawsuits alleging claims for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court and two purported securities class actions were filed in the United States District Court for the Northern District of California. PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved.

PG&E Corporation and the Utility have liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $840 million, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. In addition, coverage limits within these wildfire insurance policies could result in further material self-insured costs in the event each fire were deemed to be a separate occurrence under the terms of the insurance policies. Further, the $2.5 billion charge recorded by PG&E Corporation and the Utility for the quarter ended June 30, 2018 exceeds the amount of their insurance coverage.

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

PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "If the Utility is unable to recover all or a significant portion of its excess costs in connection with the Northern California wildfires and the Butte fire through ratemaking mechanisms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected" below.)

Losses in connection with the wildfires would likely require PG&E Corporation and the Utility to seek financing, which may not be available on terms acceptable to PG&E Corporation or the Utility, or at all, when required. (See "Risks Related to Liquidity and Capital Requirements" in Item 1A Risk Factors in 2017 Form 10-K.)

Uncertainties relating to and market perception of these matters and the disclosure of findings regarding these matters over time, also could continue or increase volatility in the market for PG&E Corporation's common stock and other securities, and for the securities of the Utility, and materially affect the price of such securities.

For more information about the Northern California wildfires, see Note 9 of the Notes to Condensed Consolidated Financial Statements in Item 1.

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

As of September 30, 2018, the Utility incurred substantial costs in connection with the Northern California wildfires and the Butte fire in excess of costs currently in rates, some of which currently are or are expected to be recorded in the future in its WEMA, 2018 CEMA and FHPMA accounts.

There can be no assurance that the Utility will be allowed to recover costs recorded in those accounts in the future. For example, while the CPUC previously approved WEMA tracking accounts for San Diego Gas & Electric Company in 2010, in December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. San Diego Gas & Electric, the Utility, and Southern California Edison filed requests for rehearing of that decision. On July 12, 2018, the CPUC voted out a decision denying the requests for rehearing.

PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover all or a significant portion of costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

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

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, and to pay fines that may be imposed in the future, as well as legal and regulatory costs. PG&E Corporation’s and the Utility’s ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation’s and the Utility’s credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including pending or anticipated litigation, the pending Cal Fire and CPUC investigations and CPUC ratemaking proceedings, substantial legislative or judicial changes to the application of inverse condemnation, and by the December 20, 2017 decision of the Boards of Directors of PG&E Corporation and the Utility to suspend dividends, as well as the perceived impact of all such matters on PG&E Corporation’s and the Utility’s financial condition, whether or not such perception is accurate.

During 2018, PG&E Corporation's and the Utility's credit ratings were subject to multiple downgrades by Fitch Ratings, S&P Global Ratings, and Moody’s Investors Service, Inc. If PG&E Corporation’s or the Utility’s credit ratings were to be further downgraded, in particular to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under “Enforcement and Litigation Matters” in Part II, Item 1. Legal Proceedings and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management’s ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation’s stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

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

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

In addition, SB 901 requires utilities to submit annual wildfire mitigation plans for approval by the CPUC on a schedule to be established by the CPUC. The wildfire mitigation plan must include the components specified in SB 901, such as identification and prioritization of wildfire risks, and drivers for those risks; plans for vegetation management; actions to harden the system, prepare for, and respond to events; and protocols for disabling reclosers and deenergizing the system. The CPUC has three months to approve a utility’s plan, with the ability to extend the deadline. The CPUC will conduct an annual compliance review, which will be supported by an independent evaluator’s report. The CPUC will complete the compliance review within 18 months. SB 901 establishes factors to be considered by the CPUC when setting penalties for failure to substantially comply with the plan. Costs associated with the wildlife mitigation plan are tracked in a memorandum account, and the costs of implementing the plan will be assessed in each utility's General Rate Case proceeding. The Utility is unable to predict the timing or outcome of the CPUC's review of the wildfire mitigation plan, the results of the CPUC compliance review of wildfire mitigation plan implementation, or the timing or extent of cost recovery for wildfire mitigation plan activities.

Finally, SB 901 established a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures. The commission, which will be composed of members with demonstrated expertise in insurance, public and private utilities, or allocation of costs and reduction of damage associated with wildfires, will hold multiple meetings throughout the state to accept public and expert testimony and develop recommendations. The commission, in consultation with the CPUC and California Insurance Commissioner, will prepare a report on or before July 1, 2019, that contains an assessment of issues surrounding catastrophic wildfire costs and damages and makes recommendations for changes to the law. The recommendations of the commission and the response by the Governor and legislature to those recommendations could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "Regulatory Matters -Legislative and Regulatory Initiatives" in Item 7. MD&A.)

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

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

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

Further, the Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. As a result, the Utility's hydroelectric generation could change and the Utility would need to consider managing or acquiring additional generation. If the

Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including gas, generation, and electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

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

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

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. (See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. Business of the Form 10-K.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives, and the CPUC approved retirement of Diablo Canyon by 2024 and 2025.

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

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;
- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion);
- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;
- operator or other human error;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;

- construction performed by third parties that damages the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines;
- the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; releases of greenhouse gases; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and
- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.

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

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

Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events, or may not be available at a reasonable cost, or available at all.

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

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

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

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

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

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

The Utility and its third-party vendors have been subject to, and will likely continue to be subject to breaches and attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these breaches or attempts has individually or in the aggregate resulted in a security incident with a material 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, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in material fines and penalties, loss of customers and harm to PG&E Corporation's and the Utility's reputation, any of which could have a material adverse 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 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 state climate policy supporting a decarbonized economy. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policymakers. California's environmental policy objectives are accelerating the pace and scope of the industry change. For instance, Senate Bill 100, which was signed into law on September 10, 2018, increases from 50 percent to 60 percent, the percentage of California's electricity portfolio that must come from renewables by 2030. SB 100 establishes a further goal to have an electric grid that is entirely powered by clean energy by 2045. California utilities also are experiencing increasing deployment by customers and third parties of DERs, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. These developments will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect DERs.

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

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

In addition, the CPUC has held discussions on potential changes to California's electricity market. On May 19, 2017, California energy companies, along with other stakeholders, discussed customer 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. After the "en banc," the CPUC formed the California Customer Choice Project to examine the issues and develop a report evaluating choice in California's current market. On August 7, 2018, the California Customer Choice Project released its report which includes an expanded discussion of policy implementation, procurement, resource adequacy, and information on a central buyer. The CPUC intends to issue a gap analysis to examine the questions raised by the Choice Paper to identify critical issues requiring solutions. The gap analysis will be accompanied by a draft action plan. The CPUC held an additional "en banc" on October 29, 2018, to discuss gap analysis and the draft action plan. While the CPUC had indicated its intent to open a proceeding related to customer choice, the Utility is unable to predict whether that remains the CPUC's intent or the timing of any such proceeding.

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.

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

During the quarter ended September 30, 2018, PG&E Corporation did not make any equity contributions to the Utility.

Issuer Purchases of Equity Securities

During the quarter ended September 30, 2018, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. During the quarter ended September 30, 2018, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. EXHIBITS

EXHIBIT INDEX

3.1	Bylaws of Pacific Gas and Electric Company amended as of August 21, 2018
4.1	Indenture, dated as of August 6, 2018, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated August 6, 2018)
4.2	First Supplemental Indenture, dated as of August 6, 2018, relating to the issuance by Pacific Gas and Electric Company of $500,000,000 aggregate principal amount of 4.25% Senior Notes due 2023 and $300,000,000 aggregate principal amount of 4.65% Senior Notes due 2028 (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated August 6, 2018)
4.3	Registration Rights Agreement, dated as of August 6, 2018, among Pacific Gas and Electric Company, Goldman Sachs & Co. LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC and SMBC Nikko Securities America, Inc., as representatives of the initial purchasers (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated August 6, 2018)
10.1	Purchase Agreement, dated as of August 2, 2018, among Pacific Gas and Electric Company, Goldman Sachs & Co. LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC and SMBC Nikko Securities America, Inc. as representatives of the initial purchasers listed on Schedules I-A and I-B thereto (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated August 6, 2018)
*10.2	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Steven E. Malnight dated September 4, 2018
*10.3	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Kathleen B. Kay dated September 4, 2018
*10.4	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective February 21, 2018
31.1	Certifications of Principal Executive Officer and Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of Principal Executive Officers and Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of Principal Executive Officer and Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of Principal Executive Officers and Principal Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document

101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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

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: November 5, 2018