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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2021

OR

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

For the transition period from ___________ to __________

Commission File Number	Exact Name of Registrant as Specified in its Charter	State or Other Jurisdiction of Incorporation	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

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

Address of principal executive offices, including zip code

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

Registrant's telephone number, including area code

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

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

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

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Indicate by check mark whether the registrant has submitted electronically 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:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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:	☒ Large accelerated filer	☐ Accelerated filer
	☐ Non-accelerated filer	
	☐ Smaller reporting company	☐ Emerging growth company
Pacific Gas and Electric Company:	☐ Large accelerated filer	☐ Accelerated filer
	☒ 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	☒ No
Pacific Gas and Electric Company:	☐ Yes	☒ No

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

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

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

Common stock outstanding as of July 26, 2021:

PG&E Corporation:	2,463,016,638*
Pacific Gas and Electric Company:	264,374,809

*Includes 477,743,590 shares of common stock held by PG&E ShareCo LLC, a wholly owned subsidiary of PG&E Corporation.

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2021
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GLOSSARY

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

2019 Wildfire Mitigation Plan	the wildfire mitigation plan for 2019 submitted by the Utility to the CPUC pursuant to SB 901, previously also referred to as the "2019 Wildfire Safety Plan"
2020 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, 2020
AB	Assembly bill
ALJ	Administrative Law Judge
ARO	asset retirement obligation
ASU	accounting standard update issued by the FASB
Backstop Commitment Letters	the Chapter 11 Plan Backstop Commitment Letters entered into by PG&E Corporation and the Backstop Parties dated as of March 6, 2020, as amended
Backstop Party	a third-party investor party to a Backstop Commitment Letter
Bankruptcy Code	the United States Bankruptcy Code
Bankruptcy Court	the U.S. Bankruptcy Court for the Northern District of California
CAISO	California Independent System Operator
Cal Fire	California Department of Forestry and Fire Protection
CCA	Community Choice Aggregator
CEMA	Catastrophic Event Memorandum Account
Chapter 11	chapter 11 of title 11 of the U.S. Code
Chapter 11 Cases	the voluntary cases commenced by each of PG&E Corporation and the Utility under Chapter 11 on January 29, 2019
CHT	customer harm threshold
Confirmation Order	the order confirming PG&E Corporation's and the Utility's and the Shareholder Proponents' Joint Chapter 11 Plan of Reorganization, dated as of June 20, 2020 with the Bankruptcy Court
CPE	central procurement entities
CPPMA	COVID-19 Pandemic Protections Memorandum Account
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
CUE	Coalition of California Utility Employees
Diablo Canyon	Diablo Canyon nuclear power plant
DTSC	Department of Toxic Substances Control
Effective Date	July 1, 2020, the effective date of the Plan in the Chapter 11 Cases
EIR	electric incident report
EMANI	European Mutual Association for Nuclear Insurance
EOEP	Enhanced Oversight and Enforcement Process
EPS	earnings per common share
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FHPMA	Fire Hazard Prevention Memorandum Account
Fire Victim Trust	trust established pursuant to the Plan for the benefit of holders of the Fire Victim Claims into which the Aggregate Fire Victim Consideration (as defined in the Plan) has been, and will continue to be funded
Formula Rate Proceedings	TO20 rate case
Forward Stock Purchase Agreements	prepaid forward contracts between PG&E Corporation and the Backstop Parties dated as of June 19, 2020
FRMMA	Fire Risk Mitigation Memorandum Account

GAAP	U.S. Generally Accepted Accounting Principles
GO	General Order
GRC	general rate case
GT&S	gas transmission and storage
HSM	Hazardous Substance Memorandum Account
IOU(s)	investor-owned utility(ies)
IRS	Internal Revenue Service
Lakeside Building	300 Lakeside Drive, Oakland, California 94612
LSE	load serving entity
MW	1 Megawatt (MW) = One thousand kilowatts
MWh	1 Megawatt-Hour (MWh) = One megawatt continuously for one hour
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
Monitor	third-party monitor retained as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction
NAV	net asset value
NBC	non-bypassable charge
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NRC	Nuclear Regulatory Commission
OEIS	On July 1, 2021, the Wildfire Safety Division became the Office of Energy Infrastructure Safety. For consistency, this Quarterly Report on Form 10-Q uses "OEIS" to refer to both.
OII	order instituting investigation
OIR	order instituting rulemaking
OSA	Office of the Safety Advocate, a division of the CPUC
PCIA	Power Charge Indifference Adjustment
PERA	Public Employees Retirement Association of New Mexico
POD	Presiding Officer's Decision
PD	proposed decision
Petition Date	January 29, 2019
the Plan	Debtors' and Shareholder Proponents' Joint Chapter 11 Plan of Reorganization, dated June 19, 2020
PSPS	Public Safety Power Shutoff
RA	resource adequacy
RAMP	Risk Assessment Mitigation Phase Report
ROE	return on equity
RSA	restructuring support agreement (as amended)
RTBA	Risk Transfer Balancing Account
RUBA	Residential Uncollectibles Balancing Accounts
SB	Senate Bill
SEC	U.S. Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
SED	Safety and Enforcement Division of the CPUC
SFGO	office space generally located at 25 Beale Street, 45 Beale Street, 77 Beale Street, 50 Main Street, 215 Market Street, and 245 Market Street, San Francisco, California 94105, and associated properties owned by the Utility
SPV	PG&E AR Facility, LLC
Tax Act	Tax Cuts and Jobs Act of 2017

TCC	Official Committee of Tort Claimants
TCC RSA	Restructuring Support Agreement dated December 6, 2019 with the TCC and attorneys and other advisors and agents for certain holders of Fire Victim Claims (as defined therein), as amended
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)
VMBA	Vegetation Management Balancing Account
WEMA	Wildfire Expense Memorandum Account
Wildfire Fund	statewide fund established by AB 1054 that will be available for eligible electric utility companies to pay eligible claims for liabilities arising from wildfires occurring after July 12, 2019 that are caused by the applicable electric utility company's equipment
Wildfires OII	Order Instituting Investigation into the 2017 Northern California wildfires and the 2018 Camp fire
WMBA	Wildfire Mitigation Balancing Account
WMCE	Wildfire Mitigation and Catastrophic Events
WMP	Wildfire Mitigation Plan
WMPMA	Wildfire Mitigation Plan Memorandum Account

FORWARD-LOOKING STATEMENTS

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

- PG&E Corporation's and the Utility's historical financial information not being indicative of future financial performance as a result of the Chapter 11 Cases and the financial and other restructuring recently undergone by PG&E Corporation and the Utility in connection with their emergence from Chapter 11;

- the risks and uncertainties associated with appeals of the Confirmation Order;

- the risks and uncertainties associated with wildfires that have occurred, are occurring or may occur in the Utility's service territory, including the wildfire that began on October 23, 2019 northeast of Geyserville in Sonoma County, California (the "2019 Kincade fire"), the wildfire that began on September 27, 2020 in the area of Zogg Mine Road and Jenny Bird Lane, north of Igo in Shasta County, California (the "2020 Zogg fire"), the wildfire that began on July 13, 2021 near the Feather River Canyon in Butte County (the "2021 Dixie fire"), and any other wildfires for which the cause has yet to be determined, the damage caused by such wildfires; the extent of the Utility's liability in connection with such wildfires (including the risk that the Utility may be found liable for damages regardless of fault); investigations into such wildfires, including those being conducted by the CPUC and the District Attorneys' offices of Sonoma, Shasta, Butte, and Plumas Counties; the outcome of the criminal proceedings initiated against the Utility by the Sonoma County District Attorney in connection with the 2019 Kincade fire, including the assertion of 33 criminal charges; the timing and outcome of the referral of the Cal Fire report to the Shasta County District Attorney in connection with the 2020 Zogg fire; potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other enforcement agency were to bring an enforcement action in respect of any such fire; the risk that the Utility is not able to recover costs from insurance, the Wildfire Fund or through rates; and the effect on PG&E Corporation's and the Utility's reputations of such wildfires, investigations and proceedings;

- the Utility's Community Wildfire Safety Program's ability to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather, including the Utility's ability to comply with the targets and metrics set forth in its WMP; whether the Utility is able to retain or contract for the workforce necessary to execute its Community Wildfire Safety Program; and the cost of the program and the timing and outcome of any proceeding to recover such costs through rates;

- the impact of wildfires, droughts, floods, high winds, lightning, extreme heat events (including recent extreme heat events during the 2021 wildfire season) 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 effectiveness of the Utility's efforts to prevent or respond to such conditions or events; 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 able to procure replacement power; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events;

- 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 risks and uncertainties associated with the Utility's ability to maintain a valid safety certification;

- the risks and uncertainties associated with the Utility's ability to access the Wildfire Fund, including whether the Wildfire Fund has sufficient remaining funds;

- the impact of the Utility's implementation of its PSPS program, including the timing and outcome of the purported PSPS class action filed in December 2019, and whether any fines, penalties or civil liability for damages will be imposed on the Utility as a result; the costs in connection with PSPS events, the timing and outcome of any proceeding to recover such costs through rates, and the effects on PG&E Corporation's and the Utility's reputations caused by implementation of the PSPS program;

- the risks and uncertainties associated with certain indemnity obligations to current and former officers and directors, as well as potential indemnity obligations to underwriters for certain of the Utility's note offerings, in connection with three purported class actions that have been consolidated and denominated *In re PG&E Corporation Securities Litigation*, U.S. District Court for the Northern District of California, Case No. 18-035509, which has been enjoined as to PG&E Corporation and the Utility pursuant to the Plan with such claims to be resolved by the Bankruptcy Court as part of the claims reconciliation process in the Chapter 11 Cases;

- the timing and outcomes of the Utility's pending and future ratemaking and regulatory proceedings, including the extent to which PG&E Corporation and the Utility are able to recover their costs through regulated rates as recorded in memorandum accounts or balancing accounts, or as otherwise requested;

- the timing and outcome in the Court of Appeals of the appeal of the FERC's order denying rehearing on March 17, 2020 granting the Utility a 50-basis point ROE incentive adder for continued participation in the CAISO;

- the outcome of current and future self-reports, investigations or other enforcement actions, or notices of violation that could be issued related to the Utility's compliance with laws, rules, regulations, or orders applicable to its gas and electric operations; the construction, expansion, or replacement of its electric and gas facilities; electric grid reliability; audit, inspection and maintenance practices; customer billing and privacy; physical and cybersecurity protections; environmental laws and regulations; or otherwise, such as fines, penalties, remediation obligations, the transfer of ownership of the Utility's assets to municipalities or other public entities, or the implementation of corporate governance, operational or in connection with the EOEP or other changes;

- the ability of the Utility to meet the conditions in its corrective action plan and exit the EOEP;

- the severity, extent and duration of the global COVID-19 pandemic and its impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows, as well as on energy demand in the Utility's service territory, the ability of the Utility to collect on customer receivables, the ability of the Utility to mitigate these effects, including with spending reductions, and the ability of the Utility to recover any losses incurred in connection with the COVID-19 pandemic, and the impact of workforce disruptions;

- the availability, cost, coverage, and terms of the Utility's insurance, including insurance for wildfire, nuclear, and other liabilities, the timing of any insurance recoveries, and recovery of the costs of such insurance or, in the event liabilities exceed insured amounts, the ability to recover uninsured losses from customers or other parties;

- increased employee attrition as a result of the challenging political and operating environment facing PG&E Corporation and the Utility;

- 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 outcome of the debarment proceeding remedial costs that the Utility may incur in connection with the outcomes including the costs of complying with any additional conditions of probation imposed in connection with the Utility's federal criminal proceeding, such as expenses associated with any material expansion of the Utility's vegetation management program, as well as the impact of additional conditions of probation on PG&E Corporation's and the Utility's ability to make distributions to shareholders;

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

- cyber or physical attacks on the Utility or its third-party vendors, contractors, or customers, which could result in operational disruption; the misappropriation or loss of confidential or proprietary assets, information or data, including customer, employee, financial, or operating system information, or intellectual property; corruption of data; or potential costs, lost revenues, or reputational harm;

- 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 that reductions in Utility customer demand for electricity and natural gas, driven by customer departures to CCAs and direct access providers, have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, and changing customer demand for its natural gas and electric services;

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

- the amount and timing of charges reflecting probable liabilities for third-party claims and 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;

- the risks and uncertainties associated with any future substantial sales of shares of common stock of PG&E Corporation by existing shareholders, including the Fire Victim Trust;

- the ability of PG&E Corporation and the Utility to securitize $7.5 billion of costs related to the multiple wildfires that began on October 8, 2017 and spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Lake, Nevada and Yuba Counties, as well as in the area surrounding Yuba City (the "2017 Northern California wildfires") in a financing transaction that is designed to be rate neutral to customers;

- 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;

- the timing and outcome of future regulation and federal, state or local legislation, their implementation, and their interpretation, the cost to comply with such regulation and legislation, and the extent to which the Utility recovers its associated compliance and investment costs, including those regarding:
    - wildfires, including inverse condemnation reform, wildfire insurance, and additional wildfire mitigation measures or other reforms targeted at the Utility or its industry;
    - the environment, including the costs incurred to discharge the Utility's remediation obligations or the costs to comply with standards for greenhouse gas emissions, renewable energy targets, energy efficiency standards, distributed energy resources, and electric vehicles;
    - the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, and cooling water intake, and the Utility's ability to continue operating Diablo Canyon until its planned retirement;
    - the regulation of utilities and their holding companies, including the conditions imposed on PG&E Corporation when it became the Utility's holding company and whether the Utility can make distributions to PG&E Corporation; and
    - taxes and tax audits,
- actions by credit rating agencies to downgrade PG&E Corporation or the Utility's credit ratings or to place those ratings on negative outlook;
- whether PG&E Corporation's and the Utility's counterparties are available and able to meet their financial and performance obligations with respect to contracts, credit agreements, and financial instruments;
- whether PG&E Corporation or the Utility undergoes an "ownership change" within the meaning of section 382 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"), as a result of which tax attributes could be limited; and
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained in Item 2. MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "Chapter 11," "Wildfire and Safety Updates" and "News & Events: Events & Presentations" tabs, respectively, in order to publicly disseminate such information. Specifically, within two hours during business hours or four hours outside of business hours of the determination that an incident is attributable or allegedly attributable to the Utility's electric facilities and has resulted in property damage estimated to exceed $50,000, a fatality or injuries requiring overnight in-patient hospitalization, or significant public or media attention, the Utility is required to submit an EIR including information about such incident. The information included in an EIR is limited and may not include important information about the facts and circumstances about the incident due to the limited scope of the reporting requirements and timing of the report and is necessarily limited to information to which the Utility has access at the time of the report. Ignitions are also reportable under CPUC Decision 14-02-015 when they involve self-propagating fire of material other than electrical or communication facilities; the fire traveled greater than one linear meter from the ignition point; and the Utility has knowledge that the fire occurred. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on such 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.

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

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Operating Revenues				
Electric	$ 3,951	$ 3,435	$ 7,346	$ 6,475
Natural gas	1,264	1,098	2,585	2,364
Total operating revenues	**5,215**	**4,533**	**9,931**	**8,839**
Operating Expenses				
Cost of electricity	847	759	1,437	1,304
Cost of natural gas	187	134	494	418
Operating and maintenance	2,583	2,141	4,919	4,108
Wildfire-related claims, net of insurance recoveries	(5)	170	167	170
Wildfire Fund expense	118	173	237	173
Depreciation, amortization, and decommissioning	851	874	1,739	1,729
Total operating expenses	**4,581**	**4,251**	**8,993**	**7,902**
Operating Income	**634**	**282**	**938**	**937**
Interest income	15	12	17	28
Interest expense	(398)	(199)	(806)	(453)
Other income, net	128	100	255	197
Reorganization items, net	(11)	(1,624)	(11)	(1,800)
Income (Loss) Before Income Taxes	**368**	**(1,429)**	**393**	**(1,091)**
Income tax provision (benefit)	(33)	539	(131)	503
Net Income (Loss)	**401**	**(1,968)**	**524**	**(1,594)**
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income (Loss) Attributable to Common Shareholders	**$ 397**	**$ (1,972)**	**$ 517**	**$ (1,601)**
Weighted Average Common Shares Outstanding, Basic	**1,985**	**529**	**1,985**	**529**
Weighted Average Common Shares Outstanding, Diluted	**2,146**	**529**	**2,146**	**529**
Net Income (Loss) Per Common Share, Basic	**$ 0.20**	**$ (3.73)**	**$ 0.26**	**$ (3.03)**
Net Income (Loss) Per Common Share, Diluted	**$ 0.18**	**$ (3.73)**	**$ 0.24**	**$ (3.03)**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2021	2020	2021	2020
Net Income (Loss)	**$ 401**	**$ (1,968)**	**$ 524**	**$ (1,594)**
Other Comprehensive Income				
Pension and other post-retirement benefit plans obligations (net of taxes of $0, $0, $0, and $0, respectively)	—	—	1	—
Total other comprehensive income	**—**	**—**	**1**	**—**
Comprehensive Income (Loss)	**401**	**(1,968)**	**525**	**(1,594)**
Preferred stock dividend requirement of subsidiary	4	4	7	7
Comprehensive Income (Loss) Attributable to Common Shareholders	**$ 397**	**$ (1,972)**	**$ 518**	**$ (1,601)**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	**June 30, 2021**	**December 31, 2020**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 307	$ 484
Restricted cash	12	143
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $304 million and $146 million at respective dates) (includes $1.67 billion and $1.63 billion related to VIEs, net of allowance for doubtful accounts of $304 million and $143 million at respective dates)	1,909	1,883
Accrued unbilled revenue (includes $1.03 billion and $959 million related to VIEs at respective dates)	1,134	1,083
Regulatory balancing accounts	2,759	2,001
Other	1,323	1,172
Regulatory assets	622	410
Inventories:		
Gas stored underground and fuel oil	44	95
Materials and supplies	521	533
Wildfire Fund asset	464	464
Other	1,194	1,334
Total current assets	**10,289**	**9,602**
Property, Plant, and Equipment		
Electric	69,239	66,982
Gas	25,082	24,135
Construction work in progress	2,778	2,757
Other	20	20
Total property, plant, and equipment	**97,119**	**93,894**
Accumulated depreciation	(28,775)	(27,758)
Net property, plant, and equipment	**68,344**	**66,136**
Other Noncurrent Assets		
Regulatory assets	8,914	8,978
Nuclear decommissioning trusts	3,697	3,538
Operating lease right of use asset	1,477	1,741
Wildfire Fund asset	5,584	5,816
Income taxes receivable	68	67
Other	2,121	1,978
Total other noncurrent assets	**21,861**	**22,118**
TOTAL ASSETS	**$ 100,494**	**$ 97,856**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	**June 30, 2021**	**December 31, 2020**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,119	$ 3,547
Long-term debt, classified as current	4,514	28
Accounts payable:		
Trade creditors	2,250	2,402
Regulatory balancing accounts	1,067	1,245
Other	653	580
Operating lease liabilities	415	533
Interest payable	480	498
Disputed claims and customer refunds	245	242
Wildfire-related claims	1,668	2,250
Other	2,082	2,256
Total current liabilities	**15,493**	**13,581**
Noncurrent Liabilities		
Long-term debt (includes $1.0 billion related to VIEs at respective dates)	35,955	37,288
Regulatory liabilities	11,218	10,424
Pension and other post-retirement benefits	2,367	2,444
Asset retirement obligations	6,554	6,412
Deferred income taxes	1,618	1,398
Operating lease liabilities	1,061	1,208
Other	4,429	3,848
Total noncurrent liabilities	**63,202**	**63,022**
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 3,600,000,000 shares at respective dates; 1,985,273,048 and 1,984,678,673 shares outstanding at respective dates	30,245	30,224
Reinvested earnings	(8,672)	(9,196)
Accumulated other comprehensive loss	(26)	(27)
Total shareholders' equity	**21,547**	**21,001**
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	**21,799**	**21,253**
TOTAL LIABILITIES AND EQUITY	**$ 100,494**	**$ 97,856**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)	
	Six Months Ended June 30,	
(in millions)	2021	2020
Cash Flows from Operating Activities		
Net income (loss)	$ 524	$ (1,594)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,739	1,729
Allowance for equity funds used during construction	(61)	(21)
Deferred income taxes and tax credits, net	228	869
Reorganization items, net (Note 2)	(62)	1,558
Wildfire Fund expense	237	173
Other	385	142
Effect of changes in operating assets and liabilities:		
Accounts receivable	(300)	(389)
Wildfire-related insurance receivable	(108)	99
Inventories	(1)	(19)
Accounts payable	119	722
Wildfire-related claims	(582)	619
Income taxes receivable/payable	—	—
Other current assets and liabilities	(281)	529
Regulatory assets, liabilities, and balancing accounts, net	(739)	(1,570)
Liabilities subject to compromise	—	413
Other noncurrent assets and liabilities	132	31
Net cash provided by operating activities	**1,230**	**3,291**
Cash Flows from Investing Activities		
Capital expenditures	(3,620)	(3,399)
Proceeds from sales and maturities of nuclear decommissioning trust investments	952	787
Purchases of nuclear decommissioning trust investments	(948)	(837)
Other	48	8
Net cash used in investing activities	**(3,568)**	**(3,441)**
Cash Flows from Financing Activities		
Proceeds from debtor-in-possession credit facility	—	500
Debtor-in-possession credit facility debt issuance costs	—	(3)
Bridge facility financing fees	—	(73)
Borrowings under revolving credit facilities	4,432	—
Repayments under revolving credit facilities	(5,867)	—
Proceeds from issuance of long-term debt, net of discount and issuance costs of $33 and $165 at respective dates	3,171	13,510
Repayment of long-term debt	(14)	—
Proceeds from sale of future revenue from transmission tower license sales, net of fees	350	—
Other	(42)	20
Net cash provided by financing activities	**2,030**	**13,954**
Net change in cash, cash equivalents, and restricted cash	**(308)**	**13,804**
Cash, cash equivalents, and restricted cash at January 1	**627**	**1,577**
Cash, cash equivalents, and restricted cash at June 30	**$ 319**	**$ 15,381**
Less: Restricted cash and restricted cash equivalents	(12)	(14,413)
Cash and cash equivalents at June 30	**$ 307**	**$ 968**

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Supplemental disclosures of cash flow information				
Cash paid for:				
Interest, net of amounts capitalized	$	(702)	$	—
Supplemental disclosures of noncash investing and financing activities				
Capital expenditures financed through accounts payable	$	614	$	273
Operating lease liabilities arising from obtaining right-of-use assets		20		13

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non-controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2020	**1,984,678,673**	**$ 30,224**	**$ (9,196)**	**$ (27)**	**$ 21,001**	**$ 252**	**$ 21,253**
Net income	—	—	123	—	123	—	123
Other comprehensive income	—	—	—	1	1	—	1
Common stock issued, net	427,030	—	—	—	—	—	—
Stock-based compensation amortization	—	2	—	—	2	—	2
Balance at March 31, 2021	**1,985,105,703**	**$ 30,226**	**$ (9,073)**	**$ (26)**	**$ 21,127**	**$ 252**	**$ 21,379**
Net income	—	—	401	—	401	—	401
Other comprehensive income	—	—	—	—	—	—	—
Common stock issued, net	167,345	—	—	—	—	—	—
Stock-based compensation amortization	—	19	—	—	19	—	19
Balance at June 30, 2021	**1,985,273,048**	**$ 30,245**	**$ (8,672)**	**$ (26)**	**$ 21,547**	**$ 252**	**$ 21,799**

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive (Loss)	Total Shareholders' Equity	Non-controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2019	**529,236,741**	**$ 13,038**	**$ (7,892)**	**$ (10)**	**$ 5,136**	**$ 252**	**$ 5,388**
Net income	—	—	374	—	374	—	374
Other comprehensive loss	—	—	—	—	—	—	—
Common stock issued, net	549,155	—	—	—	—	—	—
Stock-based compensation amortization	—	(3)	—	—	(3)	—	(3)
Balance at March 31, 2020	**529,785,896**	**$ 13,035**	**$ (7,518)**	**$ (10)**	**$ 5,507**	**$ 252**	**$ 5,759**
Net loss	—	—	(1,968)	—	(1,968)	—	(1,968)
Other comprehensive loss	—	—	—	—	—	—	—
Common stock issued, net	7,459	—	—	—	—	—	—
Stock-based compensation amortization	—	10	—	—	10	—	10
Balance at June 30, 2020	**529,793,355**	**$ 13,045**	**$ (9,486)**	**$ (10)**	**$ 3,549**	**$ 252**	**$ 3,801**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2021**	**2020**	**2021**	**2020**
Operating Revenues				
Electric	$ 3,951	$ 3,435	$ 7,346	$ 6,475
Natural gas	1,264	1,098	2,585	2,364
Total operating revenues	**5,215**	**4,533**	**9,931**	**8,839**
Operating Expenses				
Cost of electricity	847	759	1,437	1,304
Cost of natural gas	187	134	494	418
Operating and maintenance	2,581	2,145	4,912	4,110
Wildfire-related claims, net of insurance recoveries	(5)	170	167	170
Wildfire Fund expense	118	173	237	173
Depreciation, amortization, and decommissioning	851	874	1,739	1,729
Total operating expenses	**4,579**	**4,255**	**8,986**	**7,904**
Operating Income	**636**	**278**	**945**	**935**
Interest income	15	12	17	28
Interest expense	(342)	(189)	(690)	(441)
Other income, net	124	93	257	186
Reorganization items, net	(10)	(111)	(12)	(204)
Income Before Income Taxes	**423**	**83**	**517**	**504**
Income tax provision (benefit)	(17)	556	(100)	526
Net Income (Loss)	**440**	**(473)**	**617**	**(22)**
Preferred stock dividend requirement	4	4	7	7
Income (Loss) Attributable to Common Stock	**$ 436**	**$ (477)**	**$ 610**	**$ (29)**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2021	2020	2021	2020
Net Income (Loss)	$ 440	$ (473)	$ 617	$ (22)
Other Comprehensive Income				
Pension and other post-retirement benefit plans obligations (net of taxes of $0, $0, $0, and $0, respectively)	—	—	—	—
Total other comprehensive income	—	—	—	—
Comprehensive Income (Loss)	$ 440	$ (473)	$ 617	$ (22)

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	June 30, 2021	December 31, 2020
ASSETS		
Current Assets		
Cash and cash equivalents	$ 233	$ 261
Restricted cash	12	143
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $304 million and $146 million at respective dates) (includes $1.67 billion and $1.63 billion related to VIEs, net of allowance for doubtful accounts of $304 million and $143 million at respective dates)	1,909	1,883
Accrued unbilled revenue (includes $1.03 billion and $959 million related to VIEs at respective dates)	1,134	1,083
Regulatory balancing accounts	2,759	2,001
Other	1,324	1,180
Regulatory assets	622	410
Inventories:		
Gas stored underground and fuel oil	44	95
Materials and supplies	521	533
Wildfire Fund asset	464	464
Other	1,181	1,321
Total current assets	**10,203**	**9,374**
Property, Plant, and Equipment		
Electric	69,239	66,982
Gas	25,082	24,135
Construction work in progress	2,778	2,757
Other	18	18
Total property, plant, and equipment	**97,117**	**93,892**
Accumulated depreciation	(28,773)	(27,756)
Net property, plant, and equipment	**68,344**	**66,136**
Other Noncurrent Assets		
Regulatory assets	8,914	8,978
Nuclear decommissioning trusts	3,697	3,538
Operating lease right of use asset	1,474	1,736
Wildfire Fund asset	5,584	5,816
Income taxes receivable	67	66
Other	1,962	1,818
Total other noncurrent assets	**21,698**	**21,952**
TOTAL ASSETS	**$ 100,245**	**$ 97,462**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions. except share amounts)	**June 30, 2021**	**December 31, 2020**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,119	$ 3,547
Long-term debt, classified as current	4,488	—
Accounts payable:		
Trade creditors	2,249	2,366
Regulatory balancing accounts	1,067	1,245
Other	660	624
Operating lease liabilities	413	530
Interest payable	429	444
Disputed claims and customer refunds	245	242
Wildfire-related claims	1,668	2,250
Other	2,079	2,248
Total current liabilities	**15,417**	**13,496**
Noncurrent Liabilities		
Long-term debt (includes $1.0 billion related to VIEs at respective dates)	31,361	32,664
Regulatory liabilities	11,218	10,424
Pension and other post-retirement benefits	2,256	2,328
Asset retirement obligations	6,554	6,412
Deferred income taxes	1,820	1,570
Operating lease liabilities	1,061	1,206
Other	4,465	3,886
Total noncurrent liabilities	**58,735**	**58,490**
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	28,286	28,286
Reinvested earnings	(3,768)	(4,385)
Accumulated other comprehensive loss	(5)	(5)
Total shareholders' equity	**26,093**	**25,476**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 100,245**	**$ 97,462**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)	
	Six Months Ended June 30,	
(in millions)	2021	2020
Cash Flows from Operating Activities		
Net income (loss)	$ 617	$ (22)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,739	1,729
Allowance for equity funds used during construction	(61)	(21)
Deferred income taxes and tax credits, net	257	890
Reorganization items, net (Note 2)	(29)	13
Wildfire Fund expense	237	173
Other	353	138
Effect of changes in operating assets and liabilities:		
Accounts receivable	(293)	(374)
Wildfire-related insurance receivable	(108)	99
Inventories	(1)	(19)
Accounts payable	84	701
Wildfire-related claims	(582)	619
Income taxes receivable/payable	—	—
Other current assets and liabilities	(272)	(4)
Regulatory assets, liabilities, and balancing accounts, net	(739)	(1,570)
Liabilities subject to compromise	—	401
Other noncurrent assets and liabilities	133	47
Net cash provided by operating activities	**1,335**	**2,800**
Cash Flows from Investing Activities		
Capital expenditures	(3,620)	(3,399)
Proceeds from sales and maturities of nuclear decommissioning trust investments	952	787
Purchases of nuclear decommissioning trust investments	(948)	(837)
Other	48	8
Net cash used in investing activities	**(3,568)**	**(3,441)**
Cash Flows from Financing Activities		
Proceeds from debtor-in-possession credit facility	—	500
Debtor-in-possession credit facility debt issuance costs	—	(3)
Bridge facility financing fees	—	(33)
Borrowings under revolving credit facilities	4,432	—
Repayments under revolving credit facilities	(5,867)	—
Proceeds from issuance of long-term debt, net of discount and issuance costs of $33 and $75 at respective dates	3,171	8,850
Proceeds from sale of future revenue from transmission tower license sales, net of fees	350	—
Other	(12)	20
Net cash provided by financing activities	**2,074**	**9,334**
Net change in cash, cash equivalents, and restricted cash	**(159)**	**8,693**
Cash, cash equivalents, and restricted cash at January 1	**404**	**1,129**
Cash, cash equivalents, and restricted cash at June 30	**$ 245**	**$ 9,822**
Less: Restricted cash and restricted cash equivalents	(12)	(9,076)
Cash and cash equivalents at June 30	**$ 233**	**$ 746**

Supplemental disclosures of cash flow information				
Cash paid for:				
Interest, net of amounts capitalized	$	(595)	$	—
Supplemental disclosures of noncash investing and financing activities				
Capital expenditures financed through accounts payable	$	614	$	273
Operating lease liabilities arising from obtaining right-of-use assets		20		13

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions)	Preferred Stock	Common Stock Amount	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2020	**$ 258**	**$ 1,322**	**$ 28,286**	**$ (4,385)**	**$ (5)**	**$ 25,476**
Net income	—	—	—	177	—	177
Balance at March 31, 2021	**$ 258**	**$ 1,322**	**$ 28,286**	**$ (4,208)**	**$ (5)**	**$ 25,653**
Net income	—	—	—	440	—	440
Balance at June 30, 2021	**$ 258**	**$ 1,322**	**$ 28,286**	**$ (3,768)**	**$ (5)**	**$ 26,093**

(in millions)	Preferred Stock	Common Stock Amount	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2019	**$ 258**	**$ 1,322**	**$ 8,550**	**$ (4,796)**	**$ 1**	**$ 5,335**
Net income	—	—	—	451	—	451
Balance at March 31, 2020	**$ 258**	**$ 1,322**	**$ 8,550**	**$ (4,345)**	**$ 1**	**$ 5,786**
Net loss	—	—	—	(473)	—	(473)
Balance at June 30, 2020	**$ 258**	**$ 1,322**	**$ 8,550**	**$ (4,818)**	**$ 1**	**$ 5,313**

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

Organization and Basis of Presentation

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

This 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 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, 2020 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in Item 8 of the 2020 Form 10-K. This quarterly report should be read in conjunction with the 2020 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, wildfire-related liabilities, legal and regulatory contingencies, the Wildfire Fund, environmental remediation liabilities, AROs, insurance receivables, and pension and other post-retirement benefit plan 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, results of operations, liquidity, and cash flows during the period in which such change occurred.

NOTE 2: BANKRUPTCY FILING

Chapter 11 Proceedings

On the Petition Date, PG&E Corporation and the Utility commenced the Chapter 11 Cases with the Bankruptcy Court. Prior to the Effective Date, PG&E Corporation and the Utility continued to operate their business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

On June 20, 2020, the Bankruptcy Court entered the Confirmation Order confirming the Plan filed on June 19, 2020. PG&E Corporation and the Utility emerged from Chapter 11 on the Effective Date of July 1, 2020.

Except as otherwise set forth in the Plan, the Confirmation Order or another order of the Bankruptcy Court, substantially all pre-petition liabilities were discharged under the Plan.

Unresolved Chapter 11 Claims

PG&E Corporation and the Utility have received over 100,000 proofs of claim since the Petition Date, of which approximately 80,000 were channeled to the Subrogation Wildfire Trust and Fire Victim Trust. The claims channeled to the Subrogation Wildfire Trust and Fire Victim Trust will be resolved by such trusts, and PG&E Corporation and the Utility have no further liability in connection with such claims. PG&E Corporation and the Utility continue their review and analysis of certain remaining claims including asserted litigation claims, trade creditor claims, non-qualified benefit plan claims, along with other tax and regulatory claims, and therefore the ultimate liability of PG&E Corporation or the Utility for such claims may differ from the amounts asserted in such claims. Allowed claims are paid in accordance with the Plan and the Confirmation Order. Amounts expected to be allowed are reflected as current or noncurrent liabilities in the Condensed Consolidated Balance Sheets.

The Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation, other than as provided in the Plan or the Confirmation Order.

However, holders of certain claims may assert that they are entitled under the Plan or the Bankruptcy Code to pursue, or continue to pursue, their claims against PG&E Corporation and the Utility on or after the Effective Date, including but not limited to, claims arising from or relating to indemnification or contribution claims, including with respect to the wildfire that began on November 8, 2018 near the city of Paradise, Butte County, California (the "2018 Camp fire"), the 2017 Northern California wildfires, and the wildfire that began September 9, 2015 in Amador and Calaveras counties in Northern California (the "2015 Butte fire").

In addition, Subordinated Debt Claims and HoldCo Rescission or Damage Claims continue to be pursued against PG&E Corporation and the Utility in the claims reconciliation process in the Bankruptcy Court, and claims against certain former directors and current and former officers, as well as certain underwriters, are being pursued in the purported securities class action that is further described in Note 10 under the heading "Securities Class Action Litigation."

Various electricity suppliers filed claims in the Utility's 2001 prior proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility pursued settlements with electricity suppliers and entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties, in some instances, would be subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods. On May 20, 2021, the FERC approved an uncontested filing that will result in a final market clearing and funds distribution associated with the issues being considered by the FERC. Upon the completion of several intervening steps, including obtaining approval of the bankruptcy courts overseeing the Utility's prior bankruptcy proceeding as well as the bankruptcy of the California Power Exchange, the FERC will determine final amounts owed to and from the California electric IOUs. At June 30, 2021 and December 31, 2020, the Condensed Consolidated Balance Sheets reflected $245 million and $242 million, respectively, in net claims within Disputed claims and customer refunds. Pursuant to the Plan, on and after the Effective Date, the holders of such claims are entitled to pursue their claims against the Reorganized Utility as if the Chapter 11 Cases had not been commenced.

On September 1, 2020, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court requesting that the court approve an alternative dispute resolution process for resolving disputed general unsecured claims and appoint a panel of mediators in the process. On September 25, 2020, the court approved the motion and on October 28, 2020, appointed a panel of mediators. The mediators' role is to assist various claims through a Standard and Abbreviated Mediation Process.

On October 27, 2020, PG&E Corporation and the Utility filed a motion for entry of an order extending the deadline for PG&E Corporation and the Utility to object to claims, requesting an additional 180 days beyond December 31, 2020 to process claims. On April 5, 2021, the Bankruptcy Court entered an order further extending the deadline to object to claims through and including December 23, 2021, except for certain claims filed by Cal Fire, for which the deadline is September 30, 2021, in each case without prejudice to the rights of PG&E Corporation and the Utility to seek additional extensions thereof. By stipulation approved by the Bankruptcy Court, the objection deadline for certain claims asserted by the United States has been extended to October 1, 2021, November 1, 2021 or December 31, 2021, depending on the claim.

Reorganization Items, Net

Reorganization items, net, represent amounts incurred after the Petition Date as a direct result of the Chapter 11 Cases and are comprised of professional fees and financing costs, net of interest income and other. Cash paid for reorganization items, net was $2 million and $24 million for PG&E Corporation and the Utility, respectively, during the three months ended June 30, 2021 as compared to $33 million and $90 million for PG&E Corporation and the Utility, respectively, during the same period in 2020. Cash paid for reorganization items, net was $31 million and $41 million for PG&E Corporation and the Utility, respectively, during the six months ended June 30, 2021 as compared to $90 million and $207 million for PG&E Corporation and the Utility, respectively, during the same period in 2020. Reorganization items, net for the three and six months ended June 30, 2021 and 2020 include the following:

	Three Months Ended June 30, 2021		
(in millions)	**Utility**	**PG&E Corporation [1]**	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ —	$ —	$ —
Legal and other	15	1	16
Other	(5)	—	(5)
Total reorganization items, net	**$ 10**	**$ 1**	**$ 11**

[1] PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

	Three Months Ended June 30, 2020		
(in millions)	**Utility**	**PG&E Corporation [1]**	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ 1	$ —	$ 1
Legal and other [2]	110	1,513	1,623
Interest income	—	—	—
Total reorganization items, net	**$ 111**	**$ 1,513**	**$ 1,624**

[1] PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.
[2] Amount includes $1.5 billion in equity backstop premium expense, bridge loan facility fees, and trustee fees.

	Six Months Ended June 30, 2021		
(in millions)	**Utility**	**PG&E Corporation [1]**	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ —	$ —	$ —
Legal and other	21	(1)	20
Other	(9)	—	(9)
Total reorganization items, net	**$ 12**	**$ (1)**	**$ 11**

[1] PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

	Six Months Ended June 30, 2020		
(in millions)	**Utility**	**PG&E Corporation [1]**	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ 3	$ —	$ 3
Legal and other [2]	206	1,598	1,804
Interest income	(5)	(2)	(7)
Total reorganization items, net	**$ 204**	**$ 1,596**	**$ 1,800**

[1] PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.
[2] Amount includes $1.5 billion in equity backstop premium expense, bridge loan facility fees, and trustee fees.

NOTE 3: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For a summary of the significant accounting policies used by PG&E Corporation and the Utility, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 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.

Consolidated VIE

The SPV created in connection with the Receivables Securitization Program (as defined below in Note 5) in October 2020 is a bankruptcy remote, limited liability company wholly owned by the Utility, and its assets are not available to creditors of PG&E Corporation or the Utility. Pursuant to the Receivables Securitization Program, the Utility sells certain of its receivables and certain related rights to payment and obligations of the Utility with respect to such receivables, and certain other related rights to the SPV, which, in turn, obtains loans secured by the receivables from financial institutions (the "Lenders"). Amounts received from the Lenders, the pledged receivables and the corresponding debt are included in Accounts receivable and Long-term debt, respectively, on the Condensed Consolidated Balance Sheets. As of June 30, 2021, the aggregate principal amount of the loans made by the Lenders cannot exceed $1.0 billion outstanding at any time. The Receivables Securitization Program is scheduled to terminate on October 5, 2022, unless extended or earlier terminated.

The SPV is considered a VIE because its equity capitalization is insufficient to support its operations. The most significant activities that impact the economic performance of the SPV are decisions made to manage receivables. The Utility is considered the primary beneficiary and consolidates the SPV as it makes these decisions. No additional financial support was provided to the SPV during the period ended June 30, 2021 or is expected to be provided in the future that was not previously contractually required. As of June 30, 2021 and December 31, 2020, the SPV had net accounts receivable of $2.7 billion and $2.6 billion, respectively, and outstanding borrowings of $1.0 billion and $1.0 billion, respectively, under the Receivables Securitization Program.

Non-Consolidated VIEs

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at June 30, 2021, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at June 30, 2021, 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 six months ended June 30, 2021 and 2020 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(in millions)	**2021**	**2020**	**2021**	**2020**
Service cost for benefits earned [1]	$ 146	$ 132	$ 16	$ 16
Interest cost	162	179	13	15
Expected return on plan assets	(262)	(261)	(35)	(35)
Amortization of prior service cost	(2)	(2)	3	4
Amortization of net actuarial loss	2	1	(8)	(5)
Net periodic benefit cost	**46**	**49**	**(11)**	**(5)**
Regulatory account transfer [2]	37	34	—	—
Total	**$ 83**	**$ 83**	**$ (11)**	**$ (5)**

[1] A portion of service costs are capitalized pursuant to GAAP.
[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	
	Six Months Ended June 30,			
(in millions)	**2021**	**2020**	**2021**	**2020**
Service cost for benefits earned [1]	$ 293	$ 264	$ 32	$ 31
Interest cost	323	357	26	31
Expected return on plan assets	(523)	(522)	(70)	(69)
Amortization of prior service cost	(3)	(3)	7	7
Amortization of net actuarial loss	3	2	(16)	(10)
Net periodic benefit cost	**93**	**98**	**(21)**	**(10)**
Regulatory account transfer [2]	74	68	—	—
Total	**$ 167**	**$ 166**	**$ (21)**	**$ (10)**

[1] A portion of service costs are capitalized pursuant to GAAP.
[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.

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) consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended June 30, 2021		
Beginning balance	$ (38)	$ 17	$ (21)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost (net of taxes of $1 and $1, respectively)	(1)	2	1
Amortization of net actuarial loss (net of taxes of $1 and $2, respectively)	1	(6)	(5)
Regulatory account transfer (net of taxes of $0 and $1, respectively)	—	4	4
Net current period other comprehensive gain (loss)	**—**	**—**	**—**
Ending balance	**$ (38)**	**$ 17**	**$ (21)**

(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 June 30, 2020		
Beginning balance	$ (22)	$ 17	$ (5)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost (net of taxes of $1 and $1, respectively)	(1)	3	2
Amortization of net actuarial loss (net of taxes of $1 and $1, respectively)	—	(4)	(4)
Regulatory account transfer (net of taxes of $0 and $0, respectively)	1	1	2
Net current period other comprehensive gain (loss)	**—**	**—**	**—**
Ending balance	**$ (22)**	**$ 17**	**$ (5)**

(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
	Six Months Ended June 30, 2021		
Beginning balance	$ (39)	$ 17	$ (22)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost (net of taxes of $1 and $2, respectively)	(2)	5	3
Amortization of net actuarial loss (net of taxes of $1 and $4, respectively)	2	(12)	(10)
Regulatory account transfer (net of taxes of $0 and $2, respectively)	1	7	8
Net current period other comprehensive gain (loss)	**1**	**—**	**1**
Ending balance	**$ (38)**	**$ 17**	**$ (21)**

(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
	Six Months Ended June 30, 2020		
Beginning balance	$ (22)	$ 17	$ (5)
Amounts reclassified from other comprehensive income: [1]			
Amortization of prior service cost (net of taxes of $1 and $2, respectively)	(2)	5	3
Amortization of net actuarial loss (net of taxes of $1 and $3, respectively)	1	(7)	(6)
Regulatory account transfer (net of taxes of $0 and $1, respectively)	1	2	3
Net current period other comprehensive gain (loss)	—	—	—
Ending balance	**$ (22)**	**$ 17**	**$ (5)**

[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.

Revenue Recognition

Revenue from Contracts with Customers

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the 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.

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and GT&S rate cases, which have been combined in the 2023 GRC. 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2021**	**2020**	**2021**	**2020**
Electric				
Revenue from contracts with customers				
Residential	$ 1,352	$ 987	$ 2,815	$ 2,230
Commercial	1,183	1,075	2,196	2,082
Industrial	305	342	632	682
Agricultural	431	368	583	491
Public street and highway lighting	18	17	35	34
Other [1]	285	269	222	203
Total revenue from contracts with customers - electric	3,574	3,058	6,483	5,722
Regulatory balancing accounts [2]	377	377	863	753
Total electric operating revenue	**$ 3,951**	**$ 3,435**	**$ 7,346**	**$ 6,475**
Natural gas				
Revenue from contracts with customers				
Residential	$ 418	$ 426	$ 1,626	$ 1,492
Commercial	139	110	384	344
Transportation service only	346	296	672	643
Other [1]	(137)	(159)	(184)	(180)
Total revenue from contracts with customers - gas	766	673	2,498	2,299
Regulatory balancing accounts [2]	498	425	87	65
Total natural gas operating revenue	**1,264**	**1,098**	**2,585**	**2,364**
Total operating revenues	**$ 5,215**	**$ 4,533**	**$ 9,931**	**$ 8,839**

[1] This activity is primarily related to the change in unbilled revenue and amounts subject to refund, partially offset by other miscellaneous revenue items.
[2] These amounts represent revenues authorized to be billed or refunded to customers.

Initial and annual contributions to the Wildfire Fund established pursuant to AB 1054

The Wildfire Fund is expected to be capitalized with (i) $10.5 billion of proceeds of bonds supported by a 15-year extension of the Department of Water Resources charge to customers, (ii) $7.5 billion in initial contributions from California's three large electric IOUs and (iii) $300 million in annual contributions paid by California's three large electric IOUs for at least a 10 year period. The contributions from the IOUs will be effectively borne by their respective shareholders, as they will not be permitted to recover these costs from customers. The costs of the initial and annual contributions are allocated among the IOUs pursuant to a "Wildfire Fund allocation metric" set forth in AB 1054 based on land area in the applicable IOU's service territory classified as high fire threat districts and adjusted to account for risk mitigation efforts. The Utility's Wildfire Fund allocation metric is 64.2% (representing an initial contribution of approximately $4.8 billion and annual contributions of approximately $193 million).

On the Effective Date, PG&E Corporation and the Utility contributed, in accordance with AB 1054, an initial contribution of approximately $4.8 billion and first annual contribution of approximately $193 million to the Wildfire Fund to secure participation of the Utility therein. San Diego Gas & Electric Company and Southern California Edison made their initial contributions to the Wildfire Fund in September 2019. On December 30, 2020, the Utility made its second annual contribution of $193 million to the Wildfire Fund. As of June 30, 2021, PG&E Corporation and the Utility have eight remaining annual contributions of $193 million (based on the current Wildfire Fund allocation metric). PG&E Corporation and the Utility account for the contributions to the Wildfire Fund similarly to prepaid insurance with expense being allocated to periods ratably based on an estimated period of coverage.

As of June 30, 2021, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $1.3 billion in Other noncurrent liabilities, $464 million in current assets - Wildfire Fund asset, and $5.6 billion in noncurrent assets - Wildfire Fund asset in the Condensed Consolidated Balance Sheets. During the three and six months ended June 30, 2021, the Utility recorded amortization and accretion expense of $118 million and $237 million, respectively. The amortization of the asset, accretion of the liability, and if applicable, impairment of the asset is reflected in Wildfire Fund expense in the Condensed Consolidated Statements of Income. Expected contributions recorded in Wildfire Fund asset on the Condensed Consolidated Balance Sheets are discounted to the present value using the 10-year US treasury rate at the date PG&E Corporation and the Utility satisfied all the eligibility requirements to participate in the Wildfire Fund. A useful life of 15 years is being used to amortize the Wildfire Fund asset.

AB 1054 did not specify a period of coverage; therefore, this accounting treatment is subject to significant accounting judgments and estimates. In estimating the period of coverage, PG&E Corporation and the Utility use a Monte Carlo simulation that began with 12 years of historical, publicly available fire-loss data from wildfires caused by electrical equipment, and subsequently plan to add an additional year of data each following year. The period of historic fire-loss data and the effectiveness of mitigation efforts by the California electric utility companies are significant assumptions used to estimate the useful life. These assumptions along with the other assumptions below create a high degree of uncertainty related to the estimated useful life of the Wildfire Fund. The simulation creates annual distributions of potential losses due to fires that could be attributed to the participating electric utilities. Starting with a five year period of historical data, with average annual statewide claims or settlements of approximately $6.5 billion, compared to approximately $2.9 billion for the 12-year historical data, would have decreased the amortization period to six years. Similarly, a ten percent change to the assumption regarding current and future mitigation effort effectiveness would increase the amortization period to 17 years assuming greater effectiveness and would decrease the amortization period to 12 years assuming less effectiveness.

Other assumptions used to estimate the useful life include the estimated cost of wildfires caused by other electric utilities, the amount at which wildfire claims would be settled, the likely adjudication of the CPUC in cases of electric utility-caused wildfires, the impacts of climate change, the level of future insurance coverage held by the electric utilities, the FERC-allocable portion of loss recovery, and the future transmission and distribution equity rate base growth of other electric utilities. Significant changes in any of these estimates could materially impact the amortization period.

PG&E Corporation and the Utility evaluate all assumptions quarterly, or upon claims being made from the Wildfire Fund for catastrophic wildfires, and the expected life of the Wildfire Fund will be adjusted as required. The Wildfire Fund is available to other participating utilities in California and the amount of claims that a participating utility incurs is not limited to their individual contribution amounts. PG&E Corporation and the Utility will assess the Wildfire Fund asset for impairment in the event that a participating utility's electrical equipment is found to be the substantial cause of a catastrophic wildfire. Timing of any such impairment could lag as the emergence of sufficient cause and claims information can take many quarters and could be limited to public disclosure of the participating electric utility, if ignition were to occur outside the Utility's service territory. There were fires in the Utility's and other participating utilities' services territories since July 12, 2019, including fires for which the cause is currently unknown, which may in the future be determined to be covered by the Wildfire Fund. At June 30, 2021, there were no such known events requiring a reduction of the Wildfire Fund asset nor have there been any claims or withdrawals by the participating utilities against the Wildfire Fund.

Financial Instruments—Credit Losses

PG&E Corporation and the Utility have three categories of financial assets in scope, each with their own associated credit risks. PG&E Corporation and the Utility have incorporated forward-looking data in their estimate of credit loss as follows. Trade receivables are represented by customer accounts receivable and have credit exposure risk related to current economic conditions. Insurance receivables are related to the liability insurance policies PG&E Corporation and the Utility carry. Insurance receivable risk is related to each insurance carrier's risk of defaulting on their individual policies. Lastly, available-for-sale debt securities requires each company to determine if a decline in fair value is below amortized costs basis, or, impaired. Furthermore, if an impairment exists on available-for-sale debt securities, PG&E Corporation and the Utility will examine if there is an intent to sell, if it is more likely than not a requirement to sell prior to recovery, and if a portion of the unrealized loss is a result of credit loss. During the three and six months ended June 30, 2021, expected credit losses of $113 million and $189 million, respectively, were recorded in Operating and maintenance expense on the Condensed Consolidated Statements of Income for credit losses associated with trade and other receivables. During the three and six months ended June 30, 2020, expected credit losses of $44 million, respectively, were recorded to Operating and maintenance expense on the Condensed Consolidated Statements of Income. The portion of expected credit losses that are deemed probable of recovery are deferred to the RUBA, CPPMA and a FERC regulatory asset. At June 30, 2021, the RUBA current balancing accounts receivable balance was $182 million, and CPPMA and FERC long-term regulatory asset balances were $26 million and $26 million, respectively.

Sale of Transmission Tower Wireless Licenses

On February 16, 2021, the Utility granted to a subsidiary of SBA Communications Corporation (such subsidiary, "SBA") an exclusive license enabling SBA to sublicense and market wireless communications equipment attachment locations ("Cell Sites") on more than 700 of the Utility's electric transmission towers, telecommunications towers, monopoles, buildings or other structures (collectively, the "Effective Date Towers") to wireless telecommunication carriers ("Carriers") for attachment of wireless communications equipment, as contemplated by a Master Transaction Agreement (the "Transaction Agreement") dated February 2, 2021, between the Utility and SBA. Pursuant to the Transaction Agreement, the Utility also assigned to SBA license agreements between the Utility and Carriers for substantially all of the existing Cell Sites on the Effective Date Towers.

The exclusive license was granted pursuant to a Master Multi-Site License Agreement (the "License Agreement") between the Utility and SBA. The term of the License Agreement is for 100 years. The Utility has the right to terminate the license for individual Cell Sites for certain regulatory or utility operational reasons, with a corresponding payment to SBA. Pursuant to the License Agreement, SBA is entitled to the sublicensing revenue generated by new sublicenses of Cell Sites on the Effective Date Towers, subject to the Utility's right to a percentage of such sublicensing revenue.

The Utility and SBA also entered into a Master Transmission Tower Site License Agreement (the "Tower Site Agreement"), pursuant to which SBA received the exclusive rights to sublicense and market additional attachment locations on up to 28,000 of the Utility's other electric transmission towers to Carriers for attachment of wireless communications equipment. The Tower Site Agreement provides for a split of license fees from Carriers between the Utility and SBA. The Tower Site Agreement has a licensing period of up to 15 years, depending on SBA's achievement of certain performance metrics, and any sites licensed during such licensing period will continue to be subject to the Tower Site Agreement for the same term as the License Agreement.

In addition, the Utility and SBA entered into a Pipeline Cell Site Transaction Agreement pursuant to which the Utility and SBA established terms and conditions for adding additional cell sites under the License Agreement. Pipeline Cell Sites are locations where the Utility was in the process of locating a new Cell Site for a wireless carrier at the close of the transaction.

In exchange for the exclusive license and entry into the License Agreement, SBA agreed to pay the Utility a purchase price of $973 million. SBA paid the Utility $946 million of such purchase price at the closing pursuant to the Transaction Agreement, which also contemplates the post-closing assignment of additional specified Cell Sites to SBA upon the satisfaction of certain terms and conditions, for which SBA will make additional purchase price payments to the Utility. The closing settlement also reflected an adjustment for an estimated amount of payments received by the Utility from Carriers in the pre-closing period that are allocable to licenses in the post-closing period. The purchase price is subject to further adjustment pursuant to the terms of the Transaction Agreement through August 15, 2021.

The Utility recorded approximately $365 million of the $946 million sales proceeds as a financing obligation, as this portion of the proceeds for existing Cell Sites represents a sale of future revenues. The Utility recorded approximately $106 million of the $946 million sales proceeds as a contract liability (deferred revenue), as a portion of proceeds with respect to the sublicensing of Cell Sites, as well as the Tower Site Agreement represents an upfront payment for access to space on the Utility's assets. The Utility utilized a third-party discounted cash flow model based on business assumptions and estimates to determine the allocation of the purchase price between the financing obligation and deferred revenue. The financing obligation and deferred revenue are presented within Other noncurrent liabilities on the Condensed Consolidated Balance Sheets.

The Utility recorded the remaining approximately $475 million ($471 million of which was noncurrent) of the sale proceeds to regulatory liabilities, for the portion that is probable to be returned to customers in accordance with existing revenue sharing practices.

The financing obligation is amortized through Electric operating revenue and Interest expense on the Condensed Consolidated Statements of Income using the effective interest method and the deferred revenue balance is amortized through Electric operating revenue ratably over the 100-year term.

Recently Adopted Accounting Standards

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, which amends the existing guidance to reduce complexity relating to Income Tax disclosures. PG&E Corporation and the Utility adopted this ASU on January 1, 2021. There was no material impact to PG&E Corporation's or the Utility's Condensed Consolidated Financial Statements and the related disclosures resulting from the adoption of this ASU.

Accounting Standards Issued But Not Yet Adopted

Debt

In August 2020, the FASB issued ASU No. 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, which simplifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2022, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

NOTE 4: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets and Liabilities

Regulatory Assets

Long-term regulatory assets are comprised of the following:

	Balance at	
(in millions)	**June 30, 2021**	**December 31, 2020**
Pension benefits [1]	$ 2,172	$ 2,245
Environmental compliance costs	1,046	1,112
Utility retained generation [2]	156	181
Price risk management	160	204
Unamortized loss, net of gain, on reacquired debt	43	49
Catastrophic event memorandum account [3]	916	842
Wildfire expense memorandum account [4]	230	400
Fire hazard prevention memorandum account [5]	87	137
Fire risk mitigation memorandum account [6]	52	66
Wildfire mitigation plan memorandum account [7]	407	390
Deferred income taxes [8]	1,257	908
Insurance premium costs [9]	242	294
Wildfire mitigation balancing account [10]	156	156
General rate case memorandum accounts [11]	233	376
Vegetation management balancing account [12]	594	592
COVID-19 pandemic protection memorandum accounts [13]	39	84
Other	1,124	942
Total long-term regulatory assets	**$ 8,914**	**$ 8,978**

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

(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's 2001 proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

(3) Includes costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities. As of June 30, 2021, $61 million in COVID-19 related costs was recorded to CEMA regulatory assets. Recovery of CEMA costs is subject to CPUC review and approval.

(4) Includes incremental wildfire liability insurance premium costs the CPUC approved for tracking in June 2018 for the period July 26, 2017 through December 31, 2019. Recovery of WEMA costs is subject to CPUC review and approval.

(5) Includes costs associated with the implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. Recovery of FHPMA costs is subject to CPUC review and approval.

(6) Includes costs associated with the 2019 WMP for the period January 1, 2019 through June 4, 2019 and other incremental costs associated with fire risk mitigation. Recovery of FRMMA costs is subject to CPUC review and approval.

(7) Includes costs associated with the 2019 WMP for the period June 5, 2019 through December 31, 2019 and the 2020 WMP for the period of January 1, 2020 through December 31, 2020 and the 2021 WMP for the period of January 1, 2021 through June 30, 2021. Recovery of WMPMA costs is subject to CPUC review and approval.

(8) Represents cumulative differences between amounts recognized for ratemaking purposes and expense recognized in accordance with GAAP.

(9) Represents excess liability insurance premium costs recorded to RTBA and Adjustment Mechanism for Costs Determined in Other Proceedings, as authorized in the 2020 GRC and 2019 GT&S rate cases, respectively.

(10) Includes costs associated with certain wildfire mitigation activities for the period January 1, 2020 through June 30, 2021. Non-current balance represents costs above 115% of adopted revenue requirements, which are subject to CPUC review and approval.

(11) The General Rate Case Memorandum Accounts record the difference between the gas and electric revenue requirements in effect on January 1, 2020 and through February 28, 2021 as authorized by the CPUC in December 2020. These amounts will be recovered in rates over 22 months, beginning March 1, 2021.

(12) Represents costs from routine vegetation management and enhanced vegetation management activities previously recorded in the FRMMA/WMPMA, and tree mortality and fire risk reduction work previously recorded in CEMA. Recovery of VMBA costs above 120% of adopted revenue requirements is subject to CPUC review and approval.

(13) On April 16, 2020, the CPUC passed a resolution that established the CPPMA to recover costs associated with customer protections, including higher uncollectible costs related to a moratorium on electric and gas service disconnections for residential and small business customers. On a go forward basis, the CPPMA applies only to small business customers and was approved on July 27, 2020 with an effective date of March 4, 2020. The RUBA applies to residential customers and was approved on April 13, 2021 with an effective date of June 11, 2020. As of June 30, 2021, the Utility had recorded an aggregate under-collection of $208 million, representing incremental bad debt expense over what was collected in rates for the period the CPPMA and the RUBA are in effect. Of the $208 million under-collection, at June 30, 2021, $182 million is recorded in the RUBA current balancing accounts receivable and $26 million is recorded in the CPPMA. The remaining $13 million is associated with program costs and higher accounts receivable financing costs. Recovery of CPPMA costs is subject to CPUC review and approval.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at	
(in millions)	**June 30, 2021**	**December 31, 2020**
Cost of removal obligations (1)	$ 7,139	$ 6,905
Recoveries in excess of AROs (2)	496	458
Public purpose programs (3)	914	948
Employee benefit plans (4)	1,008	995
Tower Licenses (5)	451	—
Other	1,210	1,118
Total long-term regulatory liabilities	**$ 11,218**	**$ 10,424**

(1) Represents the cumulative differences between the recorded costs to remove assets and amounts collected in rates for expected costs to remove assets.

(2) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 9 below.)

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

(4) Represents cumulative differences between incurred costs and amounts collected in rates for Post-Retirement Medical, Post-Retirement Life and Long-Term Disability Plans.

(5) Represents the portion of the net proceeds received from the sale of transmission tower wireless licenses that will be returned to customers. Of the $451 million, $315 million and $136 million will be refunded to FERC and CPUC jurisdiction customers, respectively. (See Note 3 above.)

Regulatory Balancing Accounts

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

	Receivable Balance at	
(in millions)	**June 30, 2021**	**December 31, 2020**
Electric distribution	$ 207	$ —
Gas distribution and transmission	—	102
Energy procurement	481	413
Public purpose programs	299	292
Fire hazard prevention memorandum account	111	121
Fire risk mitigation memorandum account	30	33
Wildfire mitigation plan memorandum account	148	161
Wildfire mitigation balancing account	40	27
General rate case memorandum accounts	469	313
Vegetation management balancing account	142	115
Insurance premium costs	290	135
Residential uncollectibles balancing accounts	182	—
Other	360	289
Total regulatory balancing accounts receivable	**$ 2,759**	**$ 2,001**

	Payable Balance at	
(in millions)	**June 30, 2021**	**December 31, 2020**
Electric distribution	$ —	$ 55

Electric transmission	188	267
Gas distribution and transmission	125	76
Energy procurement	185	158
Public purpose programs	338	410
Other	231	279
Total regulatory balancing accounts payable	**$ 1,067**	**$ 1,245**

For more information, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K.

NOTE 5: DEBT

Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings and availability under their credit facilities at June 30, 2021:

(in millions)	Termination Date	Facility Limit	Borrowings Outstanding	Letters of Credit Outstanding	Facility Availability
Utility revolving credit facility	June 2026	$ 4,000 (1)	$ 670	$ 950	$ 2,380
Utility term loan credit facility (2)	January 2022	1,500	1,500	—	—
Utility receivables securitization program (3)	October 2022	1,000 (4)	1,000	—	— (4)
PG&E Corporation revolving credit facility	June 2024	500	—	—	500
Total credit facilities		**$ 7,000**	**$ 3,170**	**$ 950**	**$ 2,880**

(1) Includes a $1.5 billion letter of credit sublimit.
(2) On March 11, 2021, the Utility prepaid in full all amounts outstanding with respect to the $1.5 billion term loan due on June 30, 2021. The remaining $1.5 billion term loan due on January 1, 2022 remains outstanding.
(3) On October 5, 2020, the Utility entered into an accounts receivable securitization program (the "Receivables Securitization Program"), providing for the sale of a portion of the Utility's accounts receivable to the SPV, a limited liability company wholly owned by the Utility. For more information, see "Variable Interest Entities" in Note 3.
(4) The amount the Utility may borrow under the Receivables Securitization Program is limited to the lesser of the facility limit and the facility availability. The facility availability may vary based on the amount of accounts receivable that the Utility owns that are eligible for sale to the SPV and the portion of those accounts receivable that are sold to the SPV that are eligible for advances by the lenders under the Receivables Securitization Program from time to time.

Revolving Credit Facilities

Utility

As previously disclosed, on July 1, 2020, the Utility entered into a $3.5 billion revolving credit agreement (the "Utility Revolving Credit Agreement"). The Utility Revolving Credit Agreement had a maturity date of July 1, 2023, subject to two one-year extensions at the option of the Utility.

On June 22, 2021, the Utility amended the Utility Revolving Credit Agreement to, among other things, (i) increase the aggregate commitments provided by the lenders thereunder to $4 billion, (ii) extend the maturity date of such agreement to June 22, 2026 and (iii) provide for reduced interest rates and commitment fee rates based on the credit rating of the Utility.

PG&E Corporation

As previously disclosed, on July 1, 2020, PG&E Corporation entered into a $500 million revolving credit agreement (the "Corporation Revolving Credit Agreement"). The Corporation Revolving Credit Agreement had a maturity date of July 1, 2023, subject to two one-year extensions at the option of PG&E Corporation.

On June 22, 2021, PG&E Corporation amended the Corporation Revolving Credit Agreement to, among other things, (i) extend the maturity date of such agreement to June 22, 2024 and (ii) modify both the interest rate pricing grid and commitment fee pricing grid.

Long-Term Debt Issuances and Redemptions

Utility

In March 2021, the Utility issued $1.5 billion aggregate principal amount of 1.367% First Mortgage Bonds due March 10, 2023, $450 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031, and $450 million aggregate principal amount of 4.20% First Mortgage Bonds due June 1, 2041. The proceeds were used for (i) the prepayment of all of the $1.5 billion 364-day term loan facility (maturing June 30, 2021) outstanding under the Utility's term loan credit agreement, (ii) the repayment of all of the borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement and (iii) general corporate purposes.

In June 2021, the Utility issued $800 million aggregate principal amount of 3.0% First Mortgage Bonds due June 15, 2028. The proceeds were used for general corporate purposes, including the repayment of borrowings under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

NOTE 6: EQUITY

At the Market Equity Distribution Program

On April 30, 2021, PG&E Corporation entered into an Equity Distribution Agreement ("Equity Distribution Agreement") with Barclays Capital Inc., BofA Securities, Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC, as sales agents and as forward sellers (in such capacities as applicable, the "Agents" and the "Forward Sellers", respectively), and Barclays Bank PLC, Bank of America, N.A., Credit Suisse Capital LLC and Wells Fargo Bank, National Association, as forward purchasers (the "Forward Purchasers"), establishing an at-the-market equity distribution program, pursuant to which PG&E Corporation, through the Agents, may offer and sell from time to time shares of PG&E Corporation's common stock having an aggregate gross sales price of up to $400 million. PG&E Corporation has no obligation to offer or sell any of its common stock under the Equity Distribution Agreement and may at any time suspend offers under the Equity Distribution Agreement.

The Equity Distribution Agreement provides that, in addition to the issuance and sale of shares of common stock by PG&E Corporation to or through the Agents, PG&E Corporation may enter into forward sale agreements (collectively, the "Forward Sale Agreement") pursuant to which the relevant Forward Purchaser will borrow shares from third parties and, through its affiliated Forward Seller, offer a number of shares of common stock equal to the number of shares of common stock underlying the particular Forward Sale Agreement.

During the six months ended June 30, 2021, PG&E Corporation did not sell any shares pursuant to the Equity Distribution Agreement or any Forward Sale Agreement. As of June 30, 2021, there was $400 million available under PG&E Corporation's at the market equity distribution program for future offerings.

Ownership Restrictions in PG&E Corporation's Amended Articles

Under section 382 of the Internal Revenue Code, if a corporation (or a consolidated group) undergoes an "ownership change," net operating loss carryforwards and other tax attributes may be subject to certain limitations (which could limit PG&E Corporation or the Utility's ability to use these deferred tax assets to offset taxable income). In general, an ownership change occurs if the aggregate stock ownership of certain shareholders (generally five percent shareholders, applying certain look-through and aggregation rules) increases by more than 50% over such shareholders' lowest percentage ownership during the testing period (generally three years). PG&E Corporation's and the Utility's Amended Articles of Incorporation (the "Amended Articles") limit Transfers (as defined in the Amended Articles) that increase a person's or entity's (including certain groups of persons) ownership of PG&E Corporation's equity securities to 4.75% or more prior to the Restriction Release Date without approval by the Board of Directors.

Because, as of July 8, 2021, PG&E Corporation and the Utility have agreed to treat the Fire Victim Trust as a "grantor trust" for U.S. federal income tax purposes (which treatment will be retroactive to the inception of the Fire Victim Trust), any shares owned by the Fire Victim Trust are effectively excluded from the total number of outstanding equity securities when calculating a person's percentage ownership for purposes of the 4.75% ownership limitation in the Amended Articles. Shares owned by ShareCo are also effectively excluded because it is a disregarded entity for tax purposes. For example, although PG&E Corporation had 2,463,016,638 shares outstanding as of July 26, 2021, only 1,507,529,458 shares (the number of outstanding shares of common stock less the number of shares held by the Fire Victim Trust and ShareCo) count as outstanding for purposes of the ownership restrictions in the Amended Articles. As such, based on the total number of outstanding equity securities and assuming the Fire Victim Trust has not sold any shares of PG&E Corporation common stock, a person's effective percentage ownership limitation for purposes of the Amended Articles as of July 26, 2021 was 2.9%. As of July 26, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock.

As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change and consequently, its net operating loss carryforwards and other tax attributes are not limited by section 382 of the Internal Revenue Code.

PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement

The tax deduction recorded on shares provided to the Fire Victim Trust under the Plan reflects PG&E Corporation's conclusion as of June 30, 2021 that it is more likely than not that the Fire Victim Trust would be treated as a "qualified settlement fund" for U.S. federal income tax purposes, in which case the corresponding tax deduction will have occurred at the time transfers of cash and other property (including PG&E Corporation common stock) were made to the Fire Victim Trust.

In January 2021, PG&E Corporation received an IRS ruling that states the Utility is eligible to make a grantor trust election for U.S. federal income tax purposes with respect to the Fire Victim Trust and addressed certain, but not all, related issues. PG&E Corporation believed benefits associated with "grantor trust" treatment, including, a potentially larger tax deduction related to the proceeds realized by the Fire Victim Trust from the sale of shares transferred to the Fire Victim Trust, could be realized, but only if PG&E Corporation and the Fire Victim Trust could meet certain requirements of the Internal Revenue Code and Treasury Regulations thereunder, relating to sales of PG&E Corporation stock. On April 29, 2021, the Bankruptcy Court entered an order approving the material terms of an agreement (the "PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement") among PG&E Corporation, the Utility and the Fire Victim Trust that supports the election of the grantor trust treatment. On July 8, 2021, PG&E Corporation, the Utility, PG&E ShareCo LLC, a limited liability company whose sole member is PG&E Corporation ("ShareCo") and the Fire Victim Trust entered into the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement, whereby PG&E Corporation and the Utility agreed to make a "grantor trust" election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

With the "grantor trust" election, the Utility's tax deduction will occur at the time the Fire Victim Trust pays the fire victims and will be impacted by the price at which the Fire Victim Trust sells the shares, rather than the price at the time such shares were transferred to the Fire Victim Trust. Adjustments in respect of the election to treat the Fire Victim Trust as a "grantor trust" are expected to be reflected in PG&E Corporation's and the Utility's quarterly report on Form 10-Q for the quarter ending September 30, 2021.

Under the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement, the parties agreed to exchange the 477,743,590 shares of PG&E Corporation common stock issued to the Fire Victim Trust pursuant to the Plan (the "Plan Shares") for an equal number of newly-issued shares of PG&E Corporation common stock (the "New Shares"). The Plan Shares exchanged will be held thereafter by the Utility.

Pursuant to the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement, on July 9, 2021, PG&E Corporation issued 477,743,590 New Shares to ShareCo, which has the sole purpose of holding the New Shares in a designated brokerage account to facilitate the exchange process. When the Fire Victim Trust desires to sell any or all of its Plan Shares, the Fire Victim Trust may exchange any number of Plan Shares for a corresponding number of New Shares on a share-for-share basis (without any further consideration payable by either party) and thereafter promptly dispose of the New Shares in one or more transactions with one or more third parties. In the event that the Fire Victim Trust is unable to timely dispose of New Shares under certain circumstances (such shares, the “Nonconforming New Shares”), PG&E Corporation has authorized up to 250,000,000 additional shares of PG&E Corporation common stock, which may be transferred by ShareCo to the Fire Victim Trust on behalf of the Utility, in exchange for the Nonconforming New Shares, following the same procedures as for an exchange of Plan Shares for New Shares. In the event that the Fire Victim Trust disposes of any common stock subject to the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement without complying with the terms of the agreement, the Fire Victim Trust may be required to make a payment to the Utility designed to compensate the Utility for adverse tax consequences arising from nonconforming sale transactions.

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.

Subject to the dividend restrictions as described in Note 6 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K, any decision to declare and pay dividends in the future will be made at the discretion of the Boards of Directors and will depend on, among other things, results of operations, financial condition, cash requirements, contractual restrictions and other factors that the Boards of Directors may deem relevant. As of June 30, 2021, it is uncertain when PG&E Corporation and the Utility will commence the payment of dividends on their common stock and when the Utility will commence the payment of dividends on its preferred stock.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation’s basic EPS is calculated by dividing the income (loss) attributable to common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation’s income (loss) attributable to common shareholders and weighted average common shares outstanding for calculating diluted EPS:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Income (loss) attributable to common shareholders	**$ 397**	**$ (1,972)**	**$ 517**	**$ (1,601)**
Weighted average common shares outstanding, basic	1,985	529	1,985	529
Add incremental shares from assumed conversions:				
Employee share-based compensation	5	—	5	—
Equity Units	156	—	156	—
Weighted average common shares outstanding, diluted	**2,146**	**529**	**2,146**	**529**
Total income (loss) per common share, diluted	**$ 0.18**	**$ (3.73)**	**$ 0.24**	**$ (3.03)**

All potentially dilutive securities were excluded from the calculation of outstanding common shares on a diluted basis in periods where PG&E Corporation has incurred a net loss.

NOTE 8: DERIVATIVES

Use of Derivative Instruments

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

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

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

Volume of Derivative Activity

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

		Contract Volume at	
Underlying Product	**Instruments**	**June 30, 2021**	**December 31, 2020**
Natural Gas [1] (MMBtus [2])	Forwards, Futures and Swaps	252,270,326	146,642,863
	Options	35,515,000	14,140,000
Electricity (MWh)	Forwards, Futures and Swaps	10,375,299	9,435,830
	Options	411,200	—
	Congestion Revenue Rights [3]	259,232,639	266,091,470

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

Presentation of Derivative Instruments in the Financial Statements

At June 30, 2021, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 100	$ (16)	$ 76	$ 160
Noncurrent assets – other	132	—	—	132
Current liabilities – other	(45)	16	20	(9)
Noncurrent liabilities – other	(160)	—	1	(159)
Total commodity risk	**$ 27**	**$ —**	**$ 97**	**$ 124**

At December 31, 2020, the Utility's outstanding derivative balances were as follows:

Commodity Risk

(in millions)	Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$ 33	$ —	$ 115	$ 148
Noncurrent assets – other	136	—	—	136
Current liabilities – other	(38)	—	15	(23)
Noncurrent liabilities – other	(204)	—	10	(194)
Total commodity risk	**$ (73)**	**$ —**	**$ 140**	**$ 67**

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

Some of the Utility's derivatives instruments, including power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. Multiple credit agencies continue to rate the Utility below investment grade, which results in the Utility posting additional collateral. As of June 30, 2021, the Utility satisfied or has otherwise addressed its obligations related to the credit-risk related contingency features.

NOTE 9: 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				
	June 30, 2021				
(in millions)	Level 1	Level 2	Level 3	Netting [(1)]	Total
Assets:					
Short-term investments	**$ 294**	**$ —**	**$ —**	**$ —**	**$ 294**
Nuclear decommissioning trusts					
Short-term investments	10	—	—	—	**10**
Global equity securities	2,542	—	—	—	**2,542**
Fixed-income securities	1,028	829	—	—	**1,857**
Assets measured at NAV	—	—	—	—	**28**
Total nuclear decommissioning trusts [(2)]	**3,580**	**829**	**—**	**—**	**4,437**
Price risk management instruments (Note 8)					
Electricity	—	55	166	16	**237**
Gas	—	11	—	44	**55**
Total price risk management instruments	**—**	**66**	**166**	**60**	**292**
Rabbi trusts					
Fixed-income securities	—	104	—	—	**104**
Life insurance contracts	—	76	—	—	**76**

Total rabbi trusts	**—**	**180**	**—**	**—**	**180**
Long-term disability trust					
Short-term investments	6	—	—	—	**6**
Assets measured at NAV	—	—	—	—	**149**
Total long-term disability trust	**6**	**—**	**—**	**—**	**155**
TOTAL ASSETS	**$ 3,880**	**$ 1,075**	**$ 166**	**$ 60**	**$ 5,358**
Liabilities:					
Price risk management instruments (Note 8)					
Electricity	—	7	184	(24)	**167**
Gas	—	14	—	(13)	**1**
TOTAL LIABILITIES	**$ —**	**$ 21**	**$ 184**	**$ (37)**	**$ 168**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $740 million, primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements				
	December 31, 2020				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	**$ 470**	**$ —**	**$ —**	**$ —**	**$ 470**
Nuclear decommissioning trusts					
Short-term investments	27	—	—	—	**27**
Global equity securities	2,398	—	—	—	**2,398**
Fixed-income securities	924	835	—	—	**1,759**
Assets measured at NAV	—	—	—	—	**25**
Total nuclear decommissioning trusts (2)	**3,349**	**835**	**—**	**—**	**4,209**
Price risk management instruments (Note 8)					
Electricity	—	2	166	2	**170**
Gas	—	1	—	113	**114**
Total price risk management instruments	**—**	**3**	**166**	**115**	**284**
Rabbi trusts					
Fixed-income securities	—	106	—	—	**106**
Life insurance contracts	—	79	—	—	**79**
Total rabbi trusts	**—**	**185**	**—**	**—**	**185**
Long-term disability trust					
Short-term investments	9	—	—	—	**9**
Assets measured at NAV	—	—	—	—	**158**
Total long-term disability trust	**9**	**—**	**—**	**—**	**167**
TOTAL ASSETS	**$ 3,828**	**$ 1,023**	**$ 166**	**$ 115**	**$ 5,315**
Liabilities:					
Price risk management instruments (Note 8)					
Electricity	—	1	238	(25)	**214**
Gas	—	3	—	—	**3**
TOTAL LIABILITIES	**$ —**	**$ 4**	**$ 238**	**$ (25)**	**$ 217**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $671 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. There were no material transfers between any levels for the three and six months ended June 30, 2021 and 2020.

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 as 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 Uncertainty Analysis

Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact on net income resulting from changes in the fair value of these instruments. (See Note 8 above.)

(in millions)	Fair Value at June 30, 2021				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range[1]/Weighted-Average Price[2]**
Congestion revenue rights	$ 141	$ 81	Market approach	CRR auction prices	$(320.25) - $320.25 / 0.23
Power purchase agreements	$ 25	$ 103	Discounted cash flow	Forward prices	$(6.25) - $254.65 / 42.38

[1] Represents price per MWh.
[2] Unobservable inputs were weighted by the relative fair value of the instruments.

(in millions)	Fair Value at December 31, 2020				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range[1]/Weighted-Average Price[2]**
Congestion revenue rights	$ 153	$ 74	Market approach	CRR auction prices	$(320.25) - $320.25 / 0.30
Power purchase agreements	$ 13	$ 164	Discounted cash flow	Forward prices	$12.56 - $148.30 / 35.52

[1] Represents price per MWh.
[2] Unobservable inputs were weighted by the relative fair value of the instruments.

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 instruments for the three and six months ended June 30, 2021 and 2020:

	Price Risk Management Instruments	
(in millions)	**2021**	**2020**
Asset (liability) balance as of April 1	**$ (94)**	**$ (5)**
Net realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [1]	76	(61)
Asset (liability) balance as of June 30	**$ (18)**	**$ (66)**

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

	Price Risk Management Instruments	
(in millions)	**2021**	**2020**
Asset balance as of January 1	**$ (72)**	**$ 5**
Net realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [1]	54	(71)
Asset (liability) balance as of June 30	**$ (18)**	**$ (66)**

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

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable; short-term borrowings; accounts payable; and customer deposits approximate their carrying values at June 30, 2021 and December 31, 2020, as they are short-term in nature.

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

	At June 30, 2021		At December 31, 2020	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
Debt (Note 5)				
PG&E Corporation	$ 1,883	$ 2,028	$ 1,901	$ 2,175
Utility	32,849	32,891	29,664	32,632

Nuclear Decommissioning Trust Investments

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

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of June 30, 2021				
Nuclear decommissioning trusts				
Short-term investments	$ 10	$ —	$ —	$ 10
Global equity securities	508	2,064	(2)	2,570
Fixed-income securities	1,752	114	(9)	1,857
Total [(1)]	**$ 2,270**	**$ 2,178**	**$ (11)**	**$ 4,437**
As of December 31, 2020				
Nuclear decommissioning trusts				
Short-term investments	$ 27	$ —	$ —	$ 27
Global equity securities	543	1,881	(1)	2,423
Fixed-income securities	1,610	152	(3)	1,759
Total [(1)]	**$ 2,180**	**$ 2,033**	**$ (4)**	**$ 4,209**

(1) Represents amounts before deducting $740 million and $671 million for the periods ended June 30, 2021 and December 31, 2020, respectively, primarily related to deferred taxes on appreciation of investment value.

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

(in millions)	As of June 30, 2021
Less than 1 year	$ 62
1–5 years	446
5–10 years	493
More than 10 years	856
Total maturities of fixed-income securities	**$ 1,857**

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2021**	**2020**	**2021**	**2020**
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 401	$ 254	$ 952	$ 787
Gross realized gains on securities	74	8	129	76
Gross realized losses on securities	(3)	(12)	(16)	(21)

NOTE 10: WILDFIRE-RELATED CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to wildfires. A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can be reasonably estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly, and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

Restructuring Support Agreement with the TCC

On December 6, 2019, PG&E Corporation and the Utility entered into the TCC RSA. The TCC RSA (as incorporated into the Plan) provides for, among other things, a combination of cash and common stock of the reorganized PG&E Corporation to be provided by PG&E Corporation and the Utility pursuant to the Plan (together with certain additional rights, the "Aggregate Fire Victim Consideration") in order to settle and discharge the Fire Victim Claims, upon the terms and conditions set forth in the TCC RSA and the Plan. The Aggregate Fire Victim Consideration that has funded and will fund the Fire Victim Trust pursuant to the Plan for the benefit of holders of the Fire Victim Claims consists of (a) $5.4 billion in cash that was contributed on the Effective Date of the Plan, (b) $1.35 billion in cash consisting of (i) $758 million that was paid in cash on January 15, 2021 and (ii) the remaining balance of $592 million to be paid in cash on or before January 15, 2022, in each case pursuant to the terms of the tax benefits payment agreement between the Fire Victim Trust and the Utility, and (c) an amount of common stock representing 22.19% of the outstanding shares of PG&E Corporation on the Effective Date, subject to potential adjustments.

2019 Kincade Fire

According to Cal Fire, on October 23, 2019 at approximately 9:27 p.m., a wildfire began northeast of Geyserville in Sonoma County, California (the "2019 Kincade fire"), located in the service territory of the Utility. The Cal Fire Kincade Fire Incident Update dated November 20, 2019, 11:02 a.m. Pacific Time (the "incident update"), indicated that the 2019 Kincade fire had consumed 77,758 acres. In the incident update, Cal Fire reported no fatalities and four first responder injuries. The incident update also indicates the following: structures destroyed, 374 (consisting of 174 residential structures, 11 commercial structures and 189 other structures); and structures damaged, 60 (consisting of 35 residential structures, one commercial structure and 24 other structures). In connection with the 2019 Kincade fire, state and local officials issued numerous mandatory evacuation orders and evacuation warnings at various times for certain areas of the region. Based on County of Sonoma information, PG&E Corporation and the Utility understand that the geographic zones subject to either a mandatory evacuation order or an evacuation warning between October 23, 2019 and November 4, 2019 included approximately 200,000 persons.

On October 23, 2019, by 3:00 p.m. Pacific Time, the Utility had conducted a PSPS event and turned off the power to approximately 27,837 customers in Sonoma County, including Geyserville and the surrounding area. As part of the PSPS, the Utility's distribution lines in these areas were deenergized. Following the Utility's established and CPUC-approved PSPS protocols and procedures, transmission lines in these areas remained energized.

The Utility submitted EIRs to the CPUC indicating that:

- at approximately 9:19 p.m. Pacific Time on October 23, 2019, the Utility became aware of a transmission level outage on the Geysers #9 Lakeville 230 kV line when the line relayed and did not reclose;
- various generating facilities on the Geysers #9 Lakeville 230 kV line detected the disturbance and separated at approximately the same time;
- at approximately 9:21 p.m. Pacific Time, the PG&E Grid Control Center received a report that a fire had started in an area near transmission tower 001/006;
- at approximately 7:30 a.m. Pacific Time on October 24, 2019, a responding Utility troubleman patrolling the Geysers #9 Lakeville 230 kV line observed that Cal Fire had taped off the area around the base of transmission tower 001/006 in the area of the 2019 Kincade fire; and

- on site Cal Fire personnel brought to the troubleman’s attention what appeared to be a broken jumper on the same tower.

On July 16, 2020, Cal Fire issued a press release addressing the cause of the 2019 Kincade fire. The press release stated that Cal Fire had determined that “the Kincade Fire was caused by electrical transmission lines owned and operated by Pacific Gas and Electric (PG&E) located northeast of Geyserville. Tinder dry vegetation and strong winds combined with low humidity and warm temperatures contributed to extreme rates of fire spread.”

On April 6, 2021, the Sonoma County District Attorney’s office filed a criminal complaint (the “Complaint”) charging the Utility with 5 felonies and 28 misdemeanors related to the 2019 Kincade fire. The Complaint alleges three felony counts of recklessly causing a fire that caused great bodily injury to six firefighters and/or burned inhabited and other structures, inhabited property, forest land and personal property, in violation of Penal Code section 452; two felony counts of reckless emission of air contaminants that caused great bodily injury to two minors, in violation of Health and Safety Code section 42400.3(c); one misdemeanor count of carelessly or negligently throwing or placing substances that may cause a fire, in violation of Health and Safety Code section 13001; one misdemeanor count of negligently causing fire, in violation of Public Resources Code section 4421; three misdemeanor counts of violation by a public utility, in violation of Public Utilities Code section 2110; and 23 misdemeanor counts of recklessly or negligently emitting air contaminants, in violation of Health and Safety Code sections 42400.3(b) and 42400.1(a). If convicted of any of the charges in the Complaint, the Utility could be subject to fines, penalties, and restitution to victims for their economic losses (including property damage, medical and mental health expenses, lost wages, lost profits, attorney's fees and interest), as well as non-monetary remedies such as oversight requirements.

On April 6, 2021, PG&E Corporation announced that it disputed the charges in the Complaint. It further announced that it would accept Cal Fire’s finding that a Utility transmission line caused the 2019 Kincade fire, even though PG&E Corporation did not then have access to the evidence that Cal Fire gathered. On April 20, 2021, the court held an initial hearing in the case. On May 11, 2021, the Utility filed a demurrer to 25 of the 33 counts contained in the criminal complaint. The Sonoma County District Attorney’s Office filed an opposition to the demurrer on June 29, 2021. The Utility’s reply is due on August 19, 2021. The Sonoma County Superior Court is currently scheduled to conduct a hearing on the demurrer on September 9, 2021.

Potential liabilities related to the 2019 Kincade fire depend on various factors, including but not limited to the cause of the fire, contributing causes of the fire (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, fines, or restitution that may be imposed by courts or other governmental entities.

As of July 28, 2021, PG&E Corporation and the Utility are aware of 30 complaints on behalf of approximately 607 plaintiffs related to the 2019 Kincade fire and expect that they may receive further such complaints. The complaints were filed in the California Superior Court for the County of Sonoma and the California Superior Court for the County of San Francisco and include claims based on multiple theories of liability, including inverse condemnation, negligence, violations of the Public Utilities Code, violations of the Health & Safety Code, premises liability, trespass, public nuisance and private nuisance. The plaintiffs in each action principally assert that PG&E Corporation’s and the Utility’s alleged failure to properly maintain, inspect, and de-energize their transmission lines was the cause of the 2019 Kincade fire. On December 3, 2020, PG&E Corporation and the Utility filed a petition with the California Judicial Council to coordinate the litigation. On April 8, 2021, the coordination motion judge ordered that the cases be coordinated, and on April 16, 2021, the San Francisco County Superior Court was selected as the site of the coordinated proceeding. Plaintiffs filed master complaints on July 16, 2021, and PG&E Corporation’s and the Utility’s response is due by August 16, 2021.

If the Utility's facilities, such as its electric distribution and transmission lines, are judicially determined to be the substantial cause of the 2019 Kincade fire, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys' fees without having been found negligent. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Further, California courts have determined that the doctrine of inverse condemnation is applicable regardless of whether the CPUC ultimately allows recovery by the utility for any such costs. The CPUC may decide not to authorize cost recovery even if a court decision were to determine that the Utility is liable as a result of the application of the doctrine of inverse condemnation. (See "Loss Recoveries – Regulatory Recovery" below for further information regarding potential cost recovery related to the wildfires.)

In light of the current state of the law concerning inverse condemnation and the information currently available to PG&E Corporation and the Utility, including the information contained in the EIRs, Cal Fire's determination of the cause, other information gathered as part of PG&E Corporation's and the Utility's investigation, and the charges filed by the Sonoma County District Attorney's Office, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2019 Kincade fire. PG&E Corporation and the Utility recorded a charge in the aggregate amount of $625 million for the year ended December 31, 2020 (before available insurance). Based on the facts and circumstances available to the Utility as of the filing of the quarterly report on Form 10-Q for the period ended March 31, 2021 (the "Q1 Form 10-Q"), including the status of negotiations with certain subrogation entities and certain county and local agencies, PG&E Corporation and the Utility recorded an additional charge in the first quarter of 2021 for potential losses in connection with the 2019 Kincade fire of $175 million, for an aggregate liability of $800 million (before available insurance). The aggregate liability remained unchanged as of June 30, 2021.

Between the filing of PG&E Corporation's and the Utility's Q1 Form 10-Q and this filing, PG&E Corporation and the Utility entered into settlement agreements to resolve the claims of eight local public entities, including Sonoma County and the City of Santa Rosa, for an aggregate of $31 million, which amount is included in PG&E Corporation's and the Utility's $800 million charge.

The following table presents changes in the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses for claims arising from the 2019 Kincade fire since December 31, 2019.

Loss Accrual (in millions)		
Balance at December 31, 2019	$	—
Accrued Losses		625
Balance at December 31, 2020		625
Accrued Losses		175
Payments [1]		(31)
Balance at June 30, 2021	**$**	**769**

[1] As of June 30, 2021, the Utility entered into settlement agreements in connection with the 2019 Kincade fire of approximately $31 million, which has been paid in full by the Utility.

The aggregate liability of $800 million for claims in connection with the 2019 Kincade fire (before available insurance) corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses and is subject to change based on additional information. The $800 million estimate does not include, among other things: (i) any amounts for potential penalties, fines, or restitution that may be imposed by courts or other governmental entities on PG&E Corporation or the Utility, (ii) any punitive damages, (iii) any amounts in respect of compensation claims by Federal or state agencies other than state fire suppression costs, (iv) evacuation costs or (v) any other amounts that are not reasonably estimable.

Under California law (including Penal Code section 1202.4), if the Utility were convicted of any of the charges in the Complaint, the sentencing court must order the Utility to "make restitution to the victim or victims in an amount established by court order" that is "sufficient to fully reimburse the victim or victims for every determined economic loss incurred as the result of" the Utility's underlying conduct, in addition to interest and the victim's or victims' attorneys' fees. This requirement for full reimbursement of economic loss is not waivable by either the government or the victim and is not offset by any compensation that the victims have received or may receive from their insurance carriers. In the event that the Utility were convicted of certain charges in the Complaint, the Utility currently believes that, depending on which charges it were to be convicted of, its total losses associated with the 2019 Kincade fire would materially exceed the $800 million aggregate liability that PG&E Corporation and the Utility have recorded to reflect the lower end of the range of the reasonably estimable range of losses for the 2019 Kincade fire civil claims. The Utility is currently unable to determine a reasonable estimate of the amount of such additional losses. The Utility does not expect that any of its liability insurance would be available to cover restitution payments ordered by the court presiding over the criminal proceeding.

The Utility believes it will continue to receive additional information from potential claimants as litigation or resolution efforts progress. Any such additional information may potentially allow PG&E Corporation and the Utility to refine such estimate and may result in changes to the accrual depending on the information provided.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of loss could be greater than $800 million (before available insurance) but are unable to reasonably estimate the additional loss and the upper end of the range because, as described above, there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility and the outcome of the criminal proceedings initiated against the Utility by the Sonoma County District Attorney's Office. If the liability for the 2019 Kincade fire were to exceed $1.0 billion, the Utility may be eligible to make a claim to the Wildfire Fund under AB 1054 to satisfy settled or finally adjudicated eligible claims in excess of such amount, subject to the 40% limitation on the allowed amount of claims arising before emergence from bankruptcy. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in the possession of Cal Fire or the Sonoma County District Attorney's Office, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of potential damages.

The process for estimating losses associated with potential claims related to the 2019 Kincade fire requires management to exercise significant judgment based on a number of assumptions and subjective factors, including the 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 potential financial impact of the 2019 Kincade fire may change.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the 2019 Kincade fire in an aggregate amount of $430 million. The Utility records insurance recoveries when it is deemed probable that recovery will occur, and the Utility can reasonably estimate the amount or its range. As of June 30, 2021, the Utility has recorded an insurance receivable for the full amount of the $430 million. 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.

PG&E Corporation and the Utility have received data requests from the SED relating to the 2019 Kincade fire and have responded to all data requests received to date, and various other entities may also be investigating the fire. It is uncertain when any such investigations will be complete.

In addition to claims for property damage, business interruption, interest and attorneys' fees, PG&E Corporation and the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, punitive damages and other damages under other theories of liability in connection with the 2019 Kincade fire, including if PG&E Corporation or the Utility were found to have been negligent.

2020 Zogg Fire

According to Cal Fire, on September 27, 2020, a wildfire began in the area of Zogg Mine Road and Jenny Bird Lane, north of Igo in Shasta County, California (the "2020 Zogg fire"), located in the service territory of the Utility. The Cal Fire Zogg fire Incident Update dated October 16, 2020, 3:08 p.m. Pacific Time (the "incident update"), indicated that the 2020 Zogg fire had consumed 56,338 acres. The incident update reported four fatalities and one injury. The incident update also indicated that 27 structures were damaged and 204 structures were destroyed. Of the 204 structures destroyed, 63 were single family homes, according to a damage inspection report available from the Shasta County Department of Resource Management.

On October 9, 2020, the Utility submitted an EIR to the CPUC indicating that:

- wildfire camera and satellite data on September 27, 2020 show smoke, heat, or signs of fire in the area of Zogg Mine Road and Jenny Bird Lane between approximately 2:43 p.m. and 2:46 p.m. Pacific Time;

- according to Utility records, on September 27, 2020, a SmartMeter and a line recloser serving the area of Zogg Mine Road and Jenny Bird Lane reported alarms and other activity starting at approximately 2:40 p.m. until 3:06 p.m. Pacific Time when the line recloser de-energized a portion of the Girvan 1101 12 kV circuit, a distribution line that serves that area; and

- the data currently available to the Utility do not establish the causes of the activity on the Girvan 1101 circuit or the locations of these causes.

On March 22, 2021, Cal Fire issued a press release with its determination that the 2020 Zogg fire was caused by a pine tree contacting electrical facilities owned and operated by the Utility located north of the community of Igo.

Cal Fire also indicated that its investigative report has been forwarded to the Shasta County District Attorney's Office, which is investigating the matter. PG&E Corporation and the Utility have received and are responding to data requests from the SED relating to the 2020 Zogg fire and are providing information and responses to document requests from the Shasta County District Attorney's Office relating to the 2020 Zogg fire. Various other entities, which may include other law enforcement agencies, may also be investigating the fire. It is uncertain when any such investigations will be complete. PG&E Corporation and the Utility are also conducting their own investigation into the cause of the 2020 Zogg fire. This investigation is preliminary, and PG&E Corporation and the Utility do not have access to the evidence in the possession of Cal Fire or other third parties.

Potential liabilities related to the 2020 Zogg fire depend on various factors, including but not limited to the cause of the fire, contributing causes of the fire (including alternative potential origins, weather- and climate-related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the 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, fines, or restitution that may be imposed by governmental entities. If the Utility's facilities, such as its electric distribution lines, are judicially determined to be the substantial cause of the 2020 Zogg fire, 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. For more information regarding the inverse condemnation doctrine, see "2019 Kincade Fire" above.

As of July 28, 2021, PG&E Corporation and the Utility are aware of 11 complaints on behalf of approximately 297 plaintiffs related to the 2020 Zogg fire and expect that they may receive further such complaints. The complaints were filed in the California Superior Court for the County of Shasta and the California Superior Court for the County of San Francisco and include claims based on multiple theories of liability, including inverse condemnation, negligence, violations of the Public Utilities Code, violations of the Health & Safety Code, premises liability, trespass, public nuisance and private nuisance. The plaintiffs in each action principally assert that PG&E Corporation's and the Utility's alleged failure to properly maintain, inspect and de-energize their distribution lines was the cause of the 2020 Zogg fire. The plaintiffs seek damages that include wrongful death, property damage, economic loss, punitive damages, exemplary damages, attorneys' fees and other damages. On February 5, 2021, certain plaintiffs filed a petition with the California Judicial Council to coordinate five civil cases filed against the Utility and PG&E Corporation in the Superior Courts of Shasta and San Francisco counties. On May 12, 2021, the coordination motion judge ordered that the cases be coordinated, and on June 16, 2021, the San Francisco County Superior Court was selected as the site of the coordinated proceeding.

Based on the current state of the law concerning inverse condemnation in California and the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including the information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2020 Zogg fire. PG&E Corporation and the Utility recorded a charge in the aggregate amount of $275 million for the year ended December 31, 2020 (before available insurance). Based on the facts and circumstances available to the Utility as of the filing of the Q1 10-Q, including the status of negotiations with certain agencies and additional damages information from certain plaintiffs, PG&E Corporation and the Utility recorded an additional charge for potential losses in connection with the 2020 Zogg fire in the amount of $25 million for the three months ended March 31, 2021. Based on additional facts and circumstances available to the Utility as of the date of this filing, including the status of negotiations with individual plaintiffs, PG&E Corporation and the Utility recorded an additional charge for potential losses in connection with the 2020 Zogg fire of $75 million for the three months ended June 30, 2021, for an aggregate liability of $375 million (before available insurance).

Between the filing of PG&E Corporation's and the Utility's Q1 2021 Form 10-Q and this filing, PG&E Corporation and the Utility entered into settlement agreements to resolve claims for an aggregate amount of $100 million.

The following table presents changes in the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses for claims arising from the 2020 Zogg fire since December 31, 2020.

Loss Accrual (in millions)

Balance at December 31, 2020	$	275
Accrued Losses		100
Payments [1]		(67)
Balance at June 30, 2021	**$**	**308**

[1] As of June 30, 2021, the Utility entered into settlement agreements in connection with the 2020 Zogg fire of approximately $100 million, of which $67 million has been paid by the Utility. Subsequent to June 30, 2021, the Utility has entered into additional settlements and made additional payments and expects to continue to do so.

The aggregate liability of $375 million for claims in connection with the 2020 Zogg fire (before available insurance) corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses, and is subject to change based on additional information. This $375 million estimate does not include, among other things: (i) any amounts for potential penalties, fines or restitution that may be imposed by governmental entities on PG&E Corporation or the Utility, (ii) any punitive damages, (iii) any amounts in respect of compensation claims by Federal or state agencies other than state fire suppression costs, or (iv) any other amounts that are not reasonably estimable.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss will be greater than $375 million and are unable to reasonably estimate the additional loss and the upper end of the range because, as described above, 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. If the liability for the 2020 Zogg fire were to exceed $1.0 billion, the Utility may be eligible to make a claim to the Wildfire Fund under AB 1054 to satisfy settled or finally adjudicated eligible claims in excess of such amount.

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 damages and losses, the nature, number and severity of personal injuries, and information made available through the discovery process. In particular, PG&E Corporation and the Utility have not had access to all of the evidence obtained by Cal Fire or other third parties.

The process for estimating losses associated with potential claims related to the 2020 Zogg fire requires management to exercise significant judgment based on a number of assumptions and subjective factors, including the 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 potential financial impact of the 2020 Zogg fire may change.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the 2020 Zogg fire in an aggregate amount of $611 million. This amount is reduced from the $867.5 million of coverage disclosed in the 2020 Form 10-K due to the Utility's commuting certain insurance policies in connection with its April 2021 wildfire liability insurance renewal. The Utility records insurance recoveries when it is deemed probable that recovery will occur, and the Utility can reasonably estimate the amount or its range. As of June 30, 2021, the Utility has recorded an insurance receivable for $327 million for probable insurance recoveries in connection with the 2020 Zogg fire, which equals the $375 million probable loss estimate less an initial self-insured retention of $60 million, plus $12 million in legal fees incurred. PG&E Corporation and the Utility intend to seek full recovery for all insured losses. If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

In addition to claims for property damage, business interruption, interest and attorneys' fees, PG&E Corporation and the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, wrongful death and personal injury damages, punitive damages and other damages under other theories of liability in connection with the 2020 Zogg fire, including if PG&E Corporation and the Utility were found to have been negligent.

2021 Dixie Fire

On July 18, 2021, the Utility submitted an EIR (the "EIR") reporting that on July 13, 2021, at approximately 4:40 p.m. Pacific Time, a wildfire was observed in Butte County, California (the "2021 Dixie fire"), located in the service territory of the Utility. The Dixie fire has since spread to Plumas County. The Cal Fire Dixie Fire Incident Update dated July 28, 2021 at 4:36 p.m. Pacific Time (the "incident update"), indicated that the 2021 Dixie fire had consumed approximately 218,000 acres at that time. In the incident update, Cal Fire reported no fatalities, no injuries, seven structures damaged and 54 structures destroyed.

The EIR indicated that:

- On July 13, 2021 at approximately 7:00 a.m., the Utility's outage system indicated that Cresta Dam off of Highway 70 in the Feather River Canyon lost power;

- Due to the challenging terrain and road work resulting in a bridge closure, the responding Utility troubleman was not able to reach the pole with the fuse until approximately 4:40 p.m.;

- There the responding Utility troubleman observed two of three fuses blown and what appeared to him to be a healthy green tree leaning into the Bucks Creek 1101 12 kV conductor, which was still intact and suspended on the poles; and

- The responding Utility troubleman also observed a fire on the ground near the base of the tree.

Since submitting the EIR, the Utility learned that it was notified of the outage by the Rock Creek Switching Center, rather than the outage system.

On July 18, 2021, Cal Fire allowed the Utility to observe while Cal Fire took possession of some Utility equipment as part of Cal Fire's ongoing investigation into the cause of the 2021 Dixie fire. Cal Fire has not issued a determination as to the cause.

Subsequent to the ignition of the 2021 Dixie fire, according to the National Wildfire Coordinating Group's InciWeb incident overview (the "incident overview"), a wildfire began on July 22, 2021 at approximately 5:15 p.m. Pacific Time 3.5 miles north of Quincy in Plumas County, California (the "2021 Fly fire"), located in the service territory of the Utility. The incident overview reported as of July 25, 2021 at 12:00 a.m. that the 2021 Fly fire had consumed 4,300 acres and was 5% contained and that, as of the night of July 24/25, the 2021 Fly fire had merged with the 2021 Dixie fire and that the incident overview would not be providing further updates on the 2021 Fly fire.

The cause of the 2021 Dixie fire remains under investigation by Cal Fire, and PG&E Corporation and the Utility are cooperating with its investigation. The Butte County and Plumas County District Attorneys' Offices are investigating the fire, and various other entities, which may include other law enforcement agencies, may also be investigating the fire. PG&E Corporation and the Utility have received document and information requests from Cal Fire and the Butte County District Attorney's Office. It is uncertain when any such investigations will be complete. PG&E Corporation and the Utility are also conducting their own investigation into the cause of the 2021 Dixie fire. This investigation is preliminary, and PG&E Corporation and the Utility do not have access to the evidence in the possession of Cal Fire or other third parties.

Potential liabilities related to the 2021 Dixie fire depend on various factors, including but not limited to the cause of the fire, contributing causes of the fire (including alternative potential origins, weather- and climate-related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the 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, fines, or restitution that may be imposed by governmental entities. If the Utility's facilities, such as its electric distribution lines, are judicially determined to be the substantial cause of the 2021 Dixie fire, 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. For more information regarding the inverse condemnation doctrine, see "2019 Kincade Fire" above.

Based on the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including information contained in the 2021 Dixie fire EIR and other information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2021 Dixie fire. However, due to the limited amount of time that has elapsed since the start of the 2021 Dixie fire, the preliminary stages of the investigations, and the uncertainty as to the extent and magnitude of possible losses, PG&E Corporation and the Utility cannot reasonably estimate the amount or range of such possible loss at this time.

While the cause of the 2021 Dixie fire remains under investigation and there are a number of unknown facts surrounding the cause of the 2021 Dixie fire, the Utility could be subject to significant liability in connection with this fire. If such liability were to exceed insurance coverage, it could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

In addition to claims for property damage, business interruption, interest and attorneys' fees, PG&E Corporation and the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, punitive damages and other damages under other theories of liability in connection with the 2021 Dixie fire, including if PG&E Corporation or the Utility were found to have been negligent. Additional investigations and other actions may arise out of the 2021 Dixie fire. The timing and outcome for resolution of any such claims or investigations are uncertain.

Loss Recoveries

PG&E Corporation and the Utility have insurance coverage for liabilities, including wildfire. Additionally, there are several mechanisms that allow for recovery of costs from customers. Potential for recovery is described below. Failure to obtain a substantial or full recovery of costs related to wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the inability to recover costs in a timely manner could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Insurance

Insurance Coverage

In April 2021, the Utility purchased approximately $268 million in wildfire liability insurance coverage for the period of April 13, 2021 to April 1, 2022, and approximately $32 million in wildfire liability reinsurance for the period of April 1, 2021 to April 1, 2022 at a cost of approximately $220 million. This coverage is in addition to approximately $11 million in existing wildfire reinsurance for the period of July 1, 2020 to July 1, 2021 and approximately $600 million in existing wildfire liability insurance purchased by the Utility in August 2020 for the period of August 1, 2020 to August 1, 2021. On August 1, 2021, the $600 million of existing wildfire liability coverage is scheduled to renew for the period of August 1, 2021 to August 1, 2022 at a cost of approximately $516 million pursuant to multi-year policy terms. The Utility's wildfire liability insurance is subject to an initial self-insured retention of $60 million.

In June 2021, the Utility purchased approximately $535 million in non-wildfire liability coverage for the period of June 1, 2021 to April 1, 2022 at a cost of approximately $89 million. This coverage is in addition to approximately $140 million in existing non-wildfire insurance for the period of August 1, 2020 to August 1, 2021. In connection with the June 2021 renewal, the Utility procured an extension of this existing coverage to April 1, 2022 at a premium cost of approximately $30 million. The Utility also has $50 million in additional non-wildfire liability coverage available through one of its wildfire liability policies with shared limits. The Utility's non-wildfire liability insurance is subject to an initial self-insured retention of $10 million. At June 30, 2021, PG&E Corporation and the Utility had prepaid insurance of $301 million, reflected in Other current assets on the Condensed Consolidated Balance Sheets.

Various coverage limitations applicable to different insurance layers could result in material uninsured costs in the future depending on the amount and type of damages resulting from covered events.

In the Utility's 2020 GRC proceeding, the CPUC also approved a settlement agreement provision that allows the Utility to recover annual insurance costs for up to $1.4 billion in general liability insurance coverage. An advice letter is required for additional coverage purchased by the Utility in excess of $1.4 billion in coverage.

The Utility will not be able to obtain any recovery from the Wildfire Fund for wildfire-related losses in any year that do not exceed the greater of $1.0 billion in the aggregate and the amount of insurance coverage required under AB 1054. (See "Wildfire Fund under AB 1054" below.)

Insurance Receivable

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 June 30, 2021, PG&E Corporation and the Utility recorded $430 million for probable insurance recoveries in connection with the 2019 Kincade fire, and $327 million for probable insurance recoveries in connection with the 2020 Zogg fire. For the 2017 Northern California wildfires, PG&E Corporation and the Utility have recovered all of the insurance except for $25 million. PG&E Corporation and the Utility intend to seek full recovery for all insured losses.

If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The balances for insurance receivables with respect to wildfires are included in Other accounts receivable in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

Insurance Receivable (in millions)	**2020 Zogg fire**	**2019 Kincade fire**	**2017 Northern California wildfires**	**Total**
Balance at December 31, 2020	**$ 219**	**$ 430**	**$ 25**	**$ 674**
Accrued insurance recoveries	108	—	—	108
Reimbursements	—	—	—	—
Balance at June 30, 2021	**$ 327**	**$ 430**	**$ 25**	**$ 782**

Regulatory Recovery

SB 901, signed into law on September 21, 2018, requires the CPUC to establish a CHT, directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the maximum amount that the Utility can pay without harming customers or materially impacting its ability to provide adequate and safe service. SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the CHT.

Pursuant to SB 901 and the CPUC's methodology adopted in the CHT OIR, on April 30, 2020, the Utility filed an application with the CPUC seeking authorization for a post-emergence transaction to securitize $7.5 billion of 2017 wildfire claims costs that is designed to not impact amounts billed to customers, with the proceeds used to pay or reimburse the Utility for the payment of wildfire claims costs associated with the 2017 Northern California wildfires. In connection with the proposed transaction, the Utility would retire $6.0 billion of Utility debt and accelerate the remaining $592 million payment due to the Fire Victim Trust (see "Restructuring Support Agreement with the TCC" above). On April 23, 2021, the CPUC issued a decision finding that $7.5 billion of the Utility's 2017 catastrophic wildfire costs and expenses are stress test costs that may be financed through the issuance of recovery bonds pursuant to Public Utilities Code sections 850 *et seq*. Three parties filed applications for rehearing of the decision, and the Utility filed a response to those applications on May 14, 2021. On May 11, 2021, the CPUC issued a financing order authorizing the issuance of $7.5 billion of recovery bonds in connection with the rate neutral securitization proceeding. Two parties filed applications for rehearing of the financing order, and the Utility filed a response to those applications on June 4, 2021.

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

For more information see Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K.

Wildfire-Related Derivative Litigation

Two purported derivative lawsuits alleging claims for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively, naming as defendants certain then-current and former members of the Board of Directors and certain then-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 denominated In Re California North Bay Fire Derivative Litigation (now re-captioned *Trotter v. Williams et al.*). On April 13, 2018, the plaintiffs filed a consolidated complaint. After the parties reached an agreement regarding a stay of the derivative proceeding pending resolution of the tort actions described above and any regulatory proceeding relating to the 2017 Northern California wildfires, on April 24, 2018, the court entered a stipulation and order to stay. The stay was subject to certain conditions regarding the plaintiffs' access to discovery in other actions. On January 28, 2019, the plaintiffs filed a request to lift the stay for the purposes of amending their complaint to add allegations regarding the 2018 Camp fire. Prior to resolution of the plaintiffs' request to lift the stay, this matter was automatically stayed by PG&E Corporation's and the Utility's commencement of the Chapter 11 Cases. PG&E Corporation's and the Utility's rights with respect to PG&E Corporation's and the Utility's claims directly or indirectly related to any of the Fires (as defined in the Plan) against former officers and directors of PG&E Corporation and the Utility were assigned to the Fire Victim Trust under the Plan. Any such recovery is limited to the extent of any director and officer insurance policy proceeds paid by any insurance carrier to reimburse PG&E Corporation or the Utility for amounts paid pursuant to their indemnification obligations in connection with such causes of action. The assignment became effective as of the Effective Date of the Plan. On November 12, 2020, the trustee for the Fire Victim Trust filed a motion to intervene to substitute as the plaintiff in the matter, to which the parties later stipulated. On March 8, 2021, the court granted the parties' stipulation to substitute the trustee for the Fire Victim Trust as the plaintiff.

On December 24, 2018, a separate derivative lawsuit, entitled *Bowlinger v. Chew, et al.* (now captioned *Trotter v. Chew, et al.*), was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain then-current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. On February 5, 2019, the plaintiff filed a response to the notice asserting that the automatic stay did not apply to his claims. PG&E Corporation and the Utility accordingly filed a Motion to Enforce the Automatic Stay with the Bankruptcy Court as to the *Bowlinger* action, which was granted. On November 5, 2020, the court entered a stipulation and order to substitute the trustee for the Fire Victim Trust as the plaintiff.

On February 24, 2021, the trustee filed an amended complaint in the *Trotter v. Chew* action, asserting two claims for breach of fiduciary duty against certain of PG&E Corporation's and the Utility's former directors and officers. Neither PG&E Corporation nor the Utility is a party to the action. A case management conference was held on March 18, 2021 and the *Trotter v. Chew* and *Trotter v. Williams* actions were consolidated on March 30, 2021. A hearing on the defendants' demurrers and a further case management conference is scheduled for August 4, 2021. Trial is set for June 27, 2022.

On January 25, 2019, a separate purported derivative lawsuit, entitled *Hagberg v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain then-current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. A stipulation and proposed order to voluntarily dismiss this action was filed on April 20, 2021, and a case management conference on the dismissal order is set for September 8, 2021.

The above purported derivative lawsuits were brought against the named defendants on behalf of PG&E Corporation or the Utility. As a result of the assignment of these claims to the Fire Victim Trust, any recovery based on these claims would be paid to the Fire Victim Trust. Any such recovery is limited to the extent of any director and officer insurance policy proceeds paid by any insurance carrier to reimburse PG&E Corporation or the Utility for amounts paid pursuant to their indemnification obligations in connection with such causes of action.

Securities Class Action Litigation

Wildfire-Related Securities Class Action

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California, naming PG&E Corporation and certain of its then-current and former officers as defendants, entitled *David C. Weston v. PG&E Corporation, et al.* and *Jon Paul Moretti v. PG&E Corporation, et al.*, respectively. The complaints alleged material misrepresentations and omissions related to, among other things, vegetation management and transmission line safety in various PG&E Corporation public disclosures. The complaints asserted claims under section 10(b) and section 20(a) of the Exchange Act and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, interest, attorneys' fees and other costs. Both complaints identified a proposed class period of April 29, 2015 to June 8, 2018. On September 10, 2018, the court consolidated both cases, and the litigation is now denominated *In re PG&E Corporation Securities Litigation*. The court also appointed the Public Employees Retirement Association of New Mexico ("PERA") as lead plaintiff. The plaintiff filed a consolidated amended complaint on November 9, 2018. After the plaintiff requested leave to amend its complaint to add allegations regarding the 2018 Camp fire, the plaintiff filed a second amended consolidated complaint on December 14, 2018.

Due to the commencement of the Chapter 11 Cases, the proceedings were automatically stayed as to PG&E Corporation and the Utility. On February 15, 2019, PG&E Corporation and the Utility filed a complaint in Bankruptcy Court against the plaintiff seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer defendants.

On February 22, 2019, a third purported securities class action was filed in the United States District Court for the Northern District of California, entitled *York County on behalf of the York County Retirement Fund, et al. v. Rambo, et al.* (the "York County Action"). The complaint names as defendants certain then-current and former officers and directors, as well as the underwriters of four public offerings of notes from 2016 to 2018. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges material misrepresentations and omissions in connection with the note offerings related to, among other things, PG&E Corporation's and the Utility's vegetation management and wildfire safety measures. The complaint asserts claims under section 11 and section 15 of the Securities Act, and seeks unspecified monetary relief, attorneys' fees and other costs, and injunctive relief. On May 7, 2019, the York County Action was consolidated with *In re PG&E Corporation Securities Litigation.*

On May 28, 2019, the plaintiffs in the consolidated securities actions filed a third amended consolidated class action complaint, which includes the claims asserted in the previously filed actions and names as defendants PG&E Corporation, the Utility, certain current and former officers and former directors, and the underwriters. On August 28, 2019, the Bankruptcy Court denied PG&E Corporation's and the Utility's request to extend the stay to the claims against the officer, director, and underwriter defendants. On October 4, 2019, the officer, director, and underwriter defendants filed motions to dismiss the third amended complaint, which motions are under submission with the District Court. The securities actions have been enjoined as to PG&E Corporation and the Utility pursuant to the Plan with such claims to be resolved by the Bankruptcy Court as part of the claims reconciliation process in the Chapter 11 Cases. On April 29, 2021, the District Court issued a notice of intent to stay this action pending conclusion of the bankruptcy proceedings. PERA filed objections to the notice of intent to stay on May 28, 2021. PG&E Corporation and the Utility filed a response to PERA's objections on June 10, 2021, the officer, director, and underwriter defendants filed a response to PERA's objections on June 11, 2021, and PERA filed a sur-response on June 21, 2021. The District Court has not taken further action with respect to its notice of intent to stay.

Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims

Claims against PG&E Corporation and the Utility relating to, among others, the three purported securities class actions (described above) that have been consolidated and denominated *In re PG&E Corporation Securities Litigation*, U.S. District Court for the Northern District of California, Case No. 18-03509, will be resolved pursuant to the Plan. As described above, these claims consist of pre-petition claims under the federal securities laws related to, among other things, allegedly misleading statements or omissions with respect to vegetation management and wildfire safety disclosures, and are classified into separate categories under the Plan, each of which is subject to subordination under the Bankruptcy Code. The first category of claims consists of pre-petition claims arising from or related to the common stock of PG&E Corporation (such claims, with certain other similar claims against PG&E Corporation, the "HoldCo Rescission or Damage Claims"). The second category of pre-petition claims, which comprises two separate classes under the Plan, consists of claims arising from debt securities issued by PG&E Corporation and the Utility (such claims, with certain other similar claims against PG&E Corporation and the Utility, the "Subordinated Debt Claims," and together with the HoldCo Rescission or Damage Claims, the "Subordinated Claims").

While PG&E Corporation and the Utility believe they have defenses to the Subordinated Claims, as well as insurance coverage that may be available with respect to the Subordinated Claims, these defenses may not prevail and any such insurance coverage may not be adequate to cover the full amount of the allowed claims. In that case, PG&E Corporation and the Utility will be required, pursuant to the Plan, to satisfy such claims as follows:

- each holder of an allowed HoldCo Rescission or Damage Claim will receive a number of shares of common stock of PG&E Corporation equal to such holder's HoldCo Rescission or Damage Claim Share (as such term is defined in the Plan); and

- each holder of an allowed Subordinated Debt Claim will receive payment in full in cash.

PG&E Corporation and the Utility have been engaged in settlement efforts with respect to the Subordinated Claims. If the Subordinated Claims are not settled (with any such resolution being subject to the approval of the Bankruptcy Court), PG&E Corporation and the Utility expect that the Subordinated Claims will be resolved by the Bankruptcy Court in the claims reconciliation process and treated as described above under the Plan. Under the Plan, after the Effective Date, PG&E Corporation and the Utility have the authority to compromise, settle, object to, or otherwise resolve proofs of claim, and the Bankruptcy Court retains jurisdiction to hear disputes arising in connection with disputed claims. With respect to the Subordinated Claims, the claims reconciliation process may include litigation of the merits of such claims, including the filing of motions, fact discovery, and expert discovery. The total number and amount of allowed Subordinated Claims, if any, was not determined at the Effective Date. To the extent any such claims are allowed, the total amount of such claims could be material, and therefore could result in (a) the issuance of a material number of shares of common stock of PG&E Corporation with respect to allowed HoldCo Rescission or Damage Claims, or (b) the payment of a material amount of cash with respect to allowed Subordinated Debt Claims. There can be no assurance that such claims will not have a material adverse impact on PG&E Corporation's and the Utility's business, financial condition, results of operations, and cash flows.

Further, if shares are issued in respect of allowed HoldCo Rescission or Damage Claims, it may be determined that under the Plan, the Fire Victim Trust should receive additional shares of common stock of PG&E Corporation (assuming, for this purpose, that shares issued in respect of the HoldCo Rescission or Damage Claims were issued on the Effective Date).

The named plaintiffs in the consolidated securities actions filed proofs of claim with the Bankruptcy Court on or before the bar date that reflect their securities litigation claims against PG&E Corporation and the Utility. On December 9, 2019, the lead plaintiff in the consolidated securities actions filed a motion seeking approval from the Bankruptcy Court to treat its proof of claim as a class proof of claim. On February 27, 2020, the Bankruptcy Court issued an order denying the motion, but extending the bar date for putative class members to file proofs of claim until April 16, 2020. On March 6, 2020, the lead plaintiff filed a notice of appeal regarding the denial of its motion. On March 8, 2021, the District Court issued an order dismissing the appeal.

On July 2, 2020, PERA filed a notice of appeal of the Confirmation Order to the District Court, solely to the extent of seeking review of that part of the Confirmation Order approving the Insurance Deduction (as defined in the Plan) with respect to the formula for the determination of the HoldCo Rescission or Damage Claims Share. The merits of the appeal are fully briefed. On February 16, 2021, the Committee of Tort Claimants filed a motion to dismiss PERA's appeal. On March 9, 2021, PERA filed its opposition to the motion to dismiss, and on March 16, 2021, PG&E Corporation and the Utility filed a statement with respect to the motion to dismiss. The motion was taken under submission and remains pending.

On September 1, 2020, PG&E Corporation and the Utility filed a motion (the "Securities Claims Procedures Motion") with the Bankruptcy Court to approve procedures to help facilitate the resolution of the Subordinated Claims. The motion, among other things, requested approval of procedures which allow PG&E Corporation and the Utility to collect certain trading information with respect to the Subordinated Claims, to engage in an alternative dispute resolution process for resolving disputed Subordinated Claims, and to file certain omnibus claim objections with respect to the Subordinated Claims. PERA and a number of other parties filed objections to the Securities Claims Procedures Motion. On January 25, 2021, the Bankruptcy Court granted the Securities Claims Procedures Motion.

PG&E Corporation and the Utility have been working to resolve the Subordinated Claims in accordance with the procedures approved by the Bankruptcy Court, including by requesting information from Subordinated Claimants. Beginning on March 17, 2021, pursuant to the Securities Claims Procedures, PG&E Corporation and the Utility have filed in the Bankruptcy Court ten separate omnibus objections to certain of the Subordinated Claims. Between April 26 and July 22, 2021, the Bankruptcy Court entered several orders disallowing and expunging Subordinated Claims that were the subject of the first six omnibus objections. The eighth, ninth, and tenth omnibus objections and two Subordinated Claims that were the subject of the sixth and seventh omnibus objections are outstanding. PG&E Corporation and the Utility expect to file additional omnibus objections with respect to certain of the Subordinated Claims.

De-energization Securities Class Action

On October 25, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *Vataj v. Johnson et al*. The complaint named as defendants a then-current director and certain then-current and former officers of PG&E Corporation. Neither PG&E Corporation nor the Utility was named as a defendant. The complaint alleged materially false and misleading statements regarding PG&E Corporation's wildfire prevention and safety protocols and policies, including regarding the Utility's PSPS events, that allegedly resulted in losses and damages to holders of PG&E Corporation's securities. The complaint asserted claims under section 10(b) and section 20(a) of the Exchange Act and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, attorneys' fees and other costs. On February 3, 2020, the District Court granted a stipulation appointing co-lead plaintiffs and approving the selection of the plaintiffs' counsel.

On April 17, 2020, the plaintiffs filed an amended complaint asserting the same claims. The amended complaint added PG&E Corporation and a current officer of PG&E Corporation as defendants, and no longer asserts claims against certain current and former officers of PG&E Corporation previously named in the action.

On May 15, 2020, the officer defendants filed their motion to dismiss in *Vataj*. On June 19, 2020, the lead plaintiff filed its opposition to the motion to dismiss. On July 10, 2020 the officer defendants filed their reply. In October 2020, the parties reached a settlement agreement in principle, and on October 29, 2020, filed a joint notice of settlement, informing the District Court that they have agreed in principle to settle the matter.

On February 16, 2021, plaintiffs filed a motion for preliminary approval of the settlement with the District Court, and the District Court issued an order terminating as moot the pending motion to dismiss, without prejudice. Pursuant to the settlement stipulation, subject to certain conditions: (1) PG&E Corporation will pay $10 million into an interest-bearing escrow account within 14 days after the District Court's preliminary approval of the settlement; and (2) plaintiffs and the Settlement Class (as defined in the stipulation of settlement) will release the Released Persons (as defined the stipulation of settlement, including PG&E Corporation and the Utility, and each of their officers, directors, as well as the current and former officers named in both the original and amended complaints) from all claims that have been or could have been asserted by or on behalf of PG&E Corporation shareholders that relate to (a) allegations that were asserted or could have been asserted in either of the complaints in *Vataj*, and (b) investments in PG&E Corporation's stock during the relevant period specified in the stipulated settlement.

The settlement is subject to the District Court's approval and its terms may change as a result of the settlement approval process. The preliminary settlement approval hearing was held on March 11, 2021, where the District Court requested certain supplemental filings, which the parties filed on March 18, 2021. On April 20, 2021, the District Court granted the motion for preliminary approval of the settlement. On July 12, 2021, the plaintiffs filed a motion for final approval of the settlement. The final hearing to approve the settlement is scheduled for September 16, 2021. If the District Court approves the settlement and enters a judgment substantially in the form requested by the parties, the settlement will become effective when certain conditions specified in the settlement stipulation are satisfied, including the expiration of any right to appeal the judgment.

Indemnification Obligations and Directors' and Officers' Insurance Coverage

To the extent permitted by law, PG&E Corporation and the Utility have obligations to indemnify directors and officers for certain events or occurrences while a director or officer is or was serving in such capacity, which indemnification obligations extend to the claims asserted against certain directors and officers in the securities class actions and in the litigation matters enumerated above in Note 10 under the heading "Wildfire-Related Derivative Litigation." PG&E Corporation and the Utility maintain directors' and officers' insurance coverage to reduce their exposure to such indemnification obligations. PG&E Corporation and the Utility have provided notice to their insurance carriers of the claims asserted in the litigation matters enumerated in Note 10 above under the headings "Wildfire-Related Securities Class Action" and "Wildfire-Related Derivative Litigation," and are in arbitration with the carriers regarding, among other things, the applicability of multiple years of directors' and officers' insurance policies to those matters. Recovery under the directors' and officers' insurance policies in one such litigation matter may impact the directors' and officers' insurance proceeds available in the other matters.

On March 17, 2021, the trustee for the Fire Victim Trust filed a lawsuit entitled, *Trotter v. PG&E Corporation, et al.*, in San Francisco Superior Court, seeking, among other things, a declaration that the trustee for the Fire Victim Trust be permitted to participate in the arbitration with the carriers. The trustee named PG&E Corporation, the Utility, and the insurance carriers as defendants. On March 25, 2021, PG&E Corporation and the Utility removed the action to the Bankruptcy Court. On March 29, 2021, the Fire Victim Trust made a motion to remand the lawsuit back to state court, which the Bankruptcy Court denied on April 20, 2021. On April 30, 2021, the Fire Victim Trust moved for summary judgment. Oppositions and cross-motions to the summary judgment motion were filed by PG&E Corporation, the Utility and the insurance carriers on May 21, 2021. The Fire Victim Trust filed a reply on May 28, 2021, and the matter was heard on June 15, 2021. On June 22, 2021, the Bankruptcy Court entered an order denying the Fire Victim Trust's motion for summary judgment and granting the defendants' cross-motions for summary judgment. On June 29, 2021, the Bankruptcy Court entered judgment in favor of all defendants and against the Fire Victim Trust.

PG&E Corporation and the Utility additionally have potential indemnification obligations to the underwriters for the Utility's note offerings, pursuant to the underwriting agreements associated with those offerings. PG&E Corporation's and the Utility's indemnification obligations to the officers, directors and underwriters may be limited or affected by the Chapter 11 Cases, among other things.

The extent of PG&E Corporation's and the Utility's recovery of the directors' and officers' insurance proceeds could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

District Attorneys' Offices Investigations

Following the 2018 Camp fire, the Butte County District Attorney's Office and the California Attorney General's Office opened a criminal investigation of the 2018 Camp fire. PG&E Corporation and the Utility were informed by the Butte County District Attorney's Office and the California Attorney General's Office that a grand jury had been empaneled in Butte County.

On March 17, 2020, the Utility entered into the Plea Agreement and Settlement (the "Plea Agreement") with the People of the State of California, by and through the Butte County District Attorney's office to resolve the criminal prosecution of the Utility in connection with the 2018 Camp fire. Subject to the terms and conditions of the Plea Agreement, the Utility pleaded guilty to 84 counts of involuntary manslaughter in violation of Penal Code section 192(b) and one count of unlawfully causing a fire in violation of Penal Code section 452, and to admit special allegations pursuant to Penal Code sections 452.1(a)(2), 452.1(a)(3) and 452.1(a)(4).

On January 15, 2021, the Butte County Superior Court held a brief hearing on the status of restitution, which involves distribution of funds from the Fire Victim Trust, which was established under the Plan of Reorganization in Bankruptcy Court and is managed by a trustee and a claims administrator. The Court continued the hearing to August 20, 2021 for a further update.

Following the 2019 Kincade fire, the Sonoma County District Attorney's Office opened a criminal investigation of the 2019 Kincade fire. On April 6, 2021, the Sonoma County District Attorney's office filed a criminal complaint against the Utility related to the 2019 Kincade fire. For more information, see "2019 Kincade Fire" above.

On March 22, 2021, Cal Fire issued a press release with its determination that the 2020 Zogg fire was caused by a pine tree contacting electrical facilities owned and operated by the Utility located north of the community of Igo. Cal Fire also indicated that its investigative report has been forwarded to the Shasta County District Attorney's Office, which is investigating the matter. For more information, see "2020 Zogg Fire" above.

Additional investigations and other actions may arise out of the 2019 Kincade fire, the 2020 Zogg fire, or the 2021 Dixie fire. The timing and outcome for resolution of any such investigations are uncertain.

SEC Investigation

On March 20, 2019, PG&E Corporation learned that the SEC's San Francisco Regional Office was conducting an investigation related to PG&E Corporation's and the Utility's public disclosures and accounting for losses associated with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire.

On May 5, 2021, the SEC notified PG&E Corporation and the Utility that the SEC had concluded its investigation and did not intend to recommend an enforcement action.

Wildfire Fund under AB 1054

On July 12, 2019, the California governor signed into law AB 1054, a bill which provides for the establishment of a statewide fund that will be available for eligible electric utility companies to pay eligible claims for liabilities arising from wildfires occurring after July 12, 2019 that are caused by the applicable electric utility company's equipment, subject to the terms and conditions of AB 1054. Eligible claims are claims for third party damages resulting from any such wildfires, limited to the portion of such claims that exceeds the greater of (i) $1.0 billion in the aggregate in any year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to section 3293 of the Public Utilities Code, added by AB 1054.

Electric utility companies that draw from the Wildfire Fund will only be required to repay amounts that are determined by the CPUC in an application for cost recovery not to be just and reasonable, subject to a disallowance cap equal to 20% of the IOU's transmission and distribution equity rate base. For the Utility, the disallowance cap would be approximately $2.9 billion based on 2021 equity rate base, and is subject to adjustment based on changes in the Utility's total transmission and distribution equity rate base and would apply for a three calendar year period. The disallowance cap is inapplicable in certain circumstances, including if the Wildfire Fund administrator determines that the electric utility company's actions or inactions that resulted in the applicable wildfire constituted "conscious or willful disregard for the rights and safety of others," or the electric utility company fails to maintain a valid safety certification. Costs that the CPUC determines to be just and reasonable will not need to be repaid to the Wildfire Fund, resulting in a draw-down of the Wildfire Fund.

The Utility is required to attain a safety certification from the CPUC every 12 months, which will be issued within 90 days if the Utility has provided documentation that it has satisfied the requirements for the safety certification pursuant to section 8389(e) of the Public Utilities Code, added by AB 1054. On January 14, 2021, the OEIS approved the Utility's 2020 application and issued the Utility's 2020 Safety Certification pursuant to the requirements of AB 1054. The safety certification is separate from the CPUC's enforcement authority and does not preclude the CPUC from pursuing remedies for safety or other applicable violations. The 2020 Safety Certification is valid for 12 months or until a timely request for a new safety certification is acted upon, whichever occurs later. On January 26, 2021, TURN filed with the CPUC a request for review of OEIS' issuance of the safety certification, which the CPUC declined to provide on April 14, 2021.

The Wildfire Fund and disallowance cap will be terminated when the amounts therein are exhausted. The Wildfire Fund is expected to be capitalized with (i) $10.5 billion of proceeds of bonds supported by a 15-year extension of the Department of Water Resources charge to customers, (ii) $7.5 billion in initial contributions from California's three large electric IOUs and (iii) $300 million in annual contributions paid by California's three large electric IOUs for at least a 10 year period. For more information regarding contributions to the Wildfire Fund, see Note 3 above.

The Wildfire Fund will only be available for payment of eligible claims so long as there are sufficient funds remaining in the Wildfire Fund. Such funds could be depleted more quickly than expected, including as a result of claims made by California's other participating electric utility companies. The Wildfire Fund is available to pay for the Utility's eligible claims arising as of July 12, 2019, the effective date of AB 1054, subject to a limit of 40% of the allowed amount of such claims arising between the effective date of AB 1054 and the Utility's emergence from Chapter 11. The 40% limit does not apply to eligible claims that arise after the Utility's emergence from Chapter 11. The Wildfire Fund is additionally limited to the portion of such claims that exceeds the greater of (i) $1.0 billion in the aggregate in any year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to section 3293 of the Public Utilities Code, added by AB 1054.

AB 1054 also provides that the first $5.0 billion expended in the aggregate by California's three large electric IOUs on fire risk mitigation capital expenditures included in their respective approved WMPs will be excluded from their respective equity rate bases. The $5.0 billion of capital expenditures were allocated among the IOUs in accordance with their Wildfire Fund allocation metrics. The Utility's allocation is $3.21 billion. For more information on the Wildfire Fund allocation metrics, see Note 3 above. AB 1054 contemplates that such capital expenditures may be securitized through a customer charge.

AB 1054 provides that certain capital expenditures may be securitized by a customer charge. On February 24, 2021, the Utility filed an application with the CPUC seeking authorization, pursuant to AB 1054, for a transaction to securitize up to $1.19 billion of fire risk mitigation capital expenditures that have been or will be incurred by the Utility in 2020 and 2021. On June 24, 2021, the CPUC issued a financing order authorizing the issuance of up to approximately $1.2 billion of recovery bonds to recover up to $1.19 billion of fire risk mitigation capital expenditures plus an estimated $13.3 million in related upfront financing costs. On July 6, 2021, the financing order became final and non-appealable. The final amount to be securitized will be based on the capital expenditures incurred by the Utility prior to the securitization transaction.

For more information see Note 3 above and Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K.

NOTE 11: OTHER CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, penalties related to regulatory compliance, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows may be materially affected by the outcome of the following matters.

Enforcement Matters

U.S. District Court Matters and Probation

In connection with the Utility's probation proceeding, the United States District Court for the Northern District of California has the ability to impose additional probation conditions on the Utility. Additional conditions, if implemented, could be wide-ranging and would impact the Utility's operations, number of employees, costs and financial performance. Depending on the terms of these additional requirements, costs in connections with such requirements could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

CPUC and FERC Matters

Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire

On June 27, 2019, the CPUC issued the Wildfires OII to determine whether the Utility "violated any provision(s) of the California Public Utilities Code, Commission General Orders or decisions, or other applicable rules or requirements pertaining to the maintenance and operation of its electric facilities that were involved in igniting fires in its service territory in 2017." On December 5, 2019, the assigned commissioner issued a second amended scoping memo and ruling that amended the scope of issues to be considered in this proceeding to include the 2018 Camp fire.

As previously disclosed, on December 17, 2019, the Utility, the SED of the CPUC, the CPUC's OSA, and CUE jointly submitted to the CPUC a proposed settlement agreement in connection with this proceeding and jointly moved for its approval. The settlement agreement became effective on the Effective Date.

Pursuant to the settlement agreement, the Utility agreed to (i) not seek rate recovery of wildfire-related expenses and capital expenditures in future applications in the amount of $1.625 billion, as specified below, and (ii) incur costs of $50 million in shareholder-funded system enhancement initiatives as described further in the settlement agreement. The amounts set forth in the table below include actual recorded costs and forecasted cost estimates as of the date of the settlement agreement for expenses and capital expenditures which the Utility has incurred or planned to incur to comply with its legal obligations to provide safe and reliable service. While actual costs incurred for certain cost categories are different than what was assumed in the settlement agreement, the Utility has recorded $1.625 billion of the disallowed costs through June 30, 2021.

(in millions)

Description[1]	**Expense**	**Capital**	**Total**
Distribution Safety Inspections and Repairs Expense (FRMMA/WMPMA)	$ 236	$ —	$ 236
Transmission Safety Inspections and Repairs Expense (TO)[2]	433	—	433
Vegetation Management Support Costs (FHPMA)	36	—	36
2017 Northern California Wildfires CEMA Expense and Capital (CEMA)	82	66	148
2018 Camp Fire CEMA Expense (CEMA)	435	—	435
2018 Camp Fire CEMA Capital for Restoration (CEMA)	—	253	253
2018 Camp Fire CEMA Capital for Temporary Facilities (CEMA)	—	84	84
Total	**$ 1,222**	**$ 403**	**$ 1,625**

[1] All amounts included in the table reflect actual recorded costs for 2019 and 2020.
[2] Transmission amounts are under the FERC's regulatory authority.

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated.

The Utility expects that the system enhancement spending pursuant to the settlement agreement will occur through 2025.

On April 20, 2020, the assigned commissioner issued a Decision Different adopting, with changes, the proposed modifications set forth in the request for review. The Decision Different (i) increases the amount of disallowed wildfire expenditures by $198 million (as set forth in the POD); (ii) increases the amount of shareholder funding for System Enhancement Initiatives by $64 million (as set forth in the POD); (iii) imposes a $200 million fine but permanently suspends payment of the fine; and (iii) limits the tax savings that must be returned to customers to those savings generated by disallowed operating expenditures. The Decision Different also denies all pending appeals of the POD and denies, in part, the Utility's motion requesting other relief. On April 30, 2020, the Utility submitted its comments on the Decision Different to the CPUC, accepting the modifications. The CPUC approved the Decision Different on May 7, 2020.

As it relates to the additional $198 million in disallowed costs as adopted in the Decision Different, the Utility has recorded cumulative charges of $191 million primarily in the WMPMA through June 30, 2021 and intends to record the remaining charges of $7 million by the end of 2021.

On June 8, 2020, two parties filed separate applications for rehearing, the purpose of which was to challenge the CPUC's approval of the settlement agreement, as modified. On June 23, 2020, the Utility and CUE filed a joint response opposing the applications for rehearing. On December 3, 2020, the CPUC issued a decision denying the application for rehearing. On January 4, 2021, one party filed a petition for review of the CPUC decision with the California court of appeal. Responses to the petition were submitted on March 25, 2021. The Utility is unable to predict the timing and outcome of the petition.

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, March 1, 2018, and May 1, 2019 for the TO rate case for 2017 ("TO18"), the TO rate case for 2018 ("TO19"), and the TO rate case for 2019 ("TO20"), 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. On October 15, 2020, the FERC issued an order that affirmed in part and reversed in part the initial decision. The order reopens the record for the limited purpose of allowing parties an opportunity to present written evidence concerning the FERC's revised ROE methodology adopted in the FERC Opinion No. 569-A, issued on May 21, 2020. Initial briefs were filed on December 14, 2020 and reply briefs were filed on February 12, 2021. In addition, the order addresses a number of other issues including: (1) approving depreciation rates that yield an estimated composite depreciation rate of 2.94% compared to the Utility's request of 3.25%; (2) reducing forecasted capital, operations and maintenance, and cost of debt expense to actual costs incurred for the rate case period; and (3) upholding the initial decision's rejection of the Utility's direct assignment of common plant to transmission and requiring the allocation of all common plant between CPUC and FERC jurisdiction be based on operating and maintenance labor ratios. On the direct assignment issue, applying labor ratios to certain common plant would result in an allocation of 6.15% of common plant to the FERC in comparison to 8.84% under the Utility's direct assignment method. The Utility filed a request for rehearing of certain aspects of the order, which was denied by the FERC on December 17, 2020. The Utility filed a petition for review of the order on February 11, 2021 in the District of Columbia Court of Appeals. On March 4, 2021, the Court of Appeals issued an order holding the Utility's petition for review in abeyance until July 14, 2021, so that the FERC would have time to issue a substantive order on rehearing. On April 15, 2021, the FERC issued a substantive order denying the Utility's request for rehearing and granting the request for rehearing of two parties regarding the impact of the Tax Act on TO18 rates in January and February 2018. The Utility sought rehearing of the FERC's reversal on the applicability of the Tax Act on TO18 rates which may affect the timing for judicial review of the FERC order on the Utility's request for rehearing. On June 8, 2021, the Utility filed a second petition for review in the Court of Appeals on the aspects of the rehearing order other than the Tax Act. On June 17, 2021, the FERC issued a notice denying the Utility's request for rehearing on the applicability of the Tax Act on TO18 rates by operation of law and providing for further consideration. On June 21, 2021, the Court of Appeals ordered that the Utility's two petitions for review be consolidated and held both petitions in abeyance until July 14, 2021. On July 22, 2021, the Court of Appeals ordered that the Utility's two petitions for review be held in abeyance until further order of the court and directed the parties to file motions to govern further proceedings within 75 days after the FERC issues a substantive order on the Utility's request for rehearing on the applicability of the Tax Act on TO18 rates.

As a result of the FERC's April 15, 2021 order denying rehearing on the common plant allocation, the Utility increased its Regulatory liabilities for amounts previously collected during the TO18, TO19, and TO20 rate case periods from 2017 through the second quarter of 2021 by approximately $274 million. A portion of these common plant costs are expected to be recovered at the CPUC in a separate application and as a result, the Utility has recorded approximately $150 million to Regulatory assets.

On September 21, 2018, the Utility filed an all-party settlement with the FERC, which was approved by the FERC on December 20, 2018, in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined upon issuance of a final unappealable decision in the TO18 proceeding.

On December 30, 2020, the FERC approved an all-party settlement agreement in connection with TO20. The TO20 settlement resolved all issues of the Utility's formula rate. However, some of the formula rate issues are contingent on the outcome of TO18, including the allocation of costs related to common, general and intangible plant. The settlement provides that the formula rate will remain in effect through December 31, 2023. The Utility is required to make a successor rate filing in 2023, which would go into effect on January 1, 2024.

CEMA Interim Rate Relief Subject to Refund

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.

On April 25, 2019, the CPUC approved the Utility's request for interim rate relief, allowing for recovery of $373 million of costs as requested by the Utility at that time. The interim rate relief was implemented on October 1, 2019. Costs included in the interim rate relief are subject to audit and refund. On August 7, 2019, the Utility filed a revised application, revised testimony and revised workpapers, reflecting a new revenue requirement request of $669 million, pursuant to a CPUC ruling allowing these changes.

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

On March 9, 2020, the CPUC issued a modified scoping memo and ruling. On May 4, 2020, the Utility filed a revised application, which included 2019 tree mortality costs, reflecting a new revenue requirement request of $757 million.

On January 8, 2021, the Utility filed a revised application updating the revenue requirement to include an additional $5.6 million of tree mortality costs and the cost of hiring the independent auditor.

On July 2, 2021, the independent audit report of the tree mortality costs was submitted to the CPUC, recommending a $2.4 million reduction.

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

WMCE Interim Rate Relief Subject to Refund

On September 30, 2020, the Utility filed an application with the CPUC requesting cost recovery of recorded expenditures related to wildfire mitigation, certain catastrophic events, and a number of other activities (the "WMCE application"). The recorded expenditures, which exclude amounts disallowed as a result of the CPUC's decision in the OII into the 2017 Northern California wildfires and the 2018 Camp fire, consist of $1.18 billion in expense and $801 million in capital expenditures, resulting in a proposed revenue requirement of approximately $1.28 billion.

The costs addressed in the WMCE application cover activities mainly during the years 2017 to 2019 and are incremental to those previously authorized in the Utility's 2017 GRC and other proceedings. The majority of costs addressed in this application reflect work necessary to mitigate wildfire risk and to respond to catastrophic events occurring during the years 2017 to 2019. The Utility's requested revenue includes amounts for the FHPMA of $293 million, the FRMMA and the WMPMA of $740 million, and the CEMA of $251 million. The requested revenue for CEMA costs reflected in the application include the Utility's costs incurred responding to ten catastrophic events.

Given the CPUC's prior approval of $447 million in interim rate relief (which includes interest), the Utility proposed to recover the remaining $868 million revenue requirement, including interest, over a one-year period (following the conclusion of interim rate relief recovery). Cost recovery requested in this application is subject to the CPUC's reasonableness review, which could result in some or all of the interim rate relief of $447 million being subject to refund.

Hearings were held in June 2021. The scoping memo and ruling for the proceeding call for a PD to be issued in September 2021.

The Utility is unable to predict the outcome of this application. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs included in this application.

For more information regarding the FHPMA, the FRMMA, the WMPMA, and the CEMA memorandum accounts, see Note 4 above and the 2020 Form 10-K.

2015 Gas Transmission and Storage Rate Case and 2011-2014 Gas Transmission and Storage Capital Expenditures Audit

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 2011 to 2014 capital spending 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 a review of reasonableness to be conducted, or overseen, by the CPUC staff. The review was completed on June 1, 2020 and did not result in any additional disallowances. The report certified $512 million of recorded expenditures. The difference between the certified amount and the $576 million previously disallowed is primarily a result of differences between capital expenditures forecasted in the 2015 GT&S rate case and recorded capital expenditures.

On July 31, 2020, the Utility filed an application seeking recovery of $416.3 million of 2015 to 2022 revenue requirements associated with the $512 million of certified capital expenditures. On July 7, 2021, a joint motion was filed to adopt a settlement agreement. If approved by the CPUC, the settlement agreement would resolve all issues in this proceeding and would authorize a $356.3 million revenue requirement for the period of 2015 through 2022. Of this amount, $313.3 million of revenues for the period 2015 through 2021 would be amortized in rates over 60 months and $43 million associated with 2022 would be amortized in rates over 12 months through an annual gas true up filing for rates effective January 1, 2022. Going forward, the as-yet undepreciated capital plant associated with this application would be included in test year 2023 rate base in the Utility's consolidated 2023 GRC. On July 9, 2021, the ALJ granted a motion to include an additional party. The ALJ ruled that the party's participation would be limited to commenting on the settlement agreement and proposed decision, and that the party may not broaden the current scope of issues or introduce new evidentiary information.

The scoping memo calls for the issuance of a PD in the fourth quarter of 2021.

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

Other Matters

PG&E Corporation and the Utility are subject to various claims and lawsuits 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 $82 million and $134 million at June 30, 2021 and December 31, 2020, respectively. These amounts were included in Other current liabilities on the Condensed Consolidated Financial Statements. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows.

PSPS Class Action

On December 19, 2019, a complaint was filed in the United States Bankruptcy Court for the Northern District of California naming PG&E Corporation and the Utility. The plaintiff seeks certification of a class consisting of all California residents and business owners who had their power shut off by the Utility during the October 9, October 23, October 26, October 28, or November 20, 2019 power outages and any subsequent voluntary outages occurring during the course of litigation. The plaintiff alleges that the necessity for the October and November 2019 power shutoff events was caused by the Utility's negligence in failing to properly maintain its electrical lines and surrounding vegetation. The complaint seeks up to $2.5 billion in special and general damages, punitive and exemplary damages and injunctive relief to require the Utility to properly maintain and inspect its power grid. PG&E Corporation and the Utility believe the allegations are without merit and intend to defend this lawsuit vigorously.

On January 21, 2020, PG&E Corporation and the Utility filed a motion to dismiss the complaint or in the alternative strike the class action allegations. On March 30, 2020, the Bankruptcy Court granted the Utility's motion to dismiss this class action because the plaintiff's class action claims are preempted as a matter of law by the CPUC code. On April 3, 2020, the Bankruptcy Court entered an order dismissing the action without leave to amend.

The plaintiff appealed the decision dismissing the complaint to the District Court. On March 26, 2021, the District Court affirmed the Bankruptcy Court's dismissal of this action, and the plaintiff filed a notice of appeal to the Ninth Circuit Court of Appeals. The appellant filed his opening brief on June 25, 2021. A former executive director of the CPUC filed an amicus brief on July 2, 2021, asking the Ninth Circuit to reverse the decision of the District Court and to remand the case for further proceedings. The answering brief of PG&E Corporation and the Utility is due by August 25, 2021. The appellants' reply brief is due 21 days after the answering brief is filed.

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

CZU Lightning Complex Fire Notices of Violation

Between November 2020 and January 2021, several governmental entities raised concerns regarding the Utility's emergency response to the 2020 CZU Lightning Complex fire, including Cal Fire, the California Coastal Commission, the Central Coast Regional Water Quality Control Board, and Santa Cruz County Board of Supervisors alleging environmental and unpermitted work violations. In the matter of Santa Cruz County's complaint with the CPUC, on July 2, 2021, the CPUC issued a ruling denying the Utility's motion to dismiss but limiting the issues to be determined to whether the Utility's activities in response to the 2020 CZU Lightning Complex fire violated the Utility's obligations under certain sections of Public Utilities Code and CPUC orders. The CPUC set a deadline of November 19, 2021 for interested parties to submit testimony and scheduled evidentiary hearings in late January 2022. The Utility continues to work with all agencies, as well as Santa Cruz County, to resolve any outstanding issues.

Based on the information currently available, PG&E Corporation and the Utility believe it is probable that a liability has been incurred. The Utility is unable to reasonably estimate the amount or range of potential penalties that could be incurred given the number of factors that can be considered in determining penalties. PG&E Corporation and the Utility do not believe that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows. Violations can result in penalties, remediation and other relief.

Diablo Canyon Nuclear Power Plant

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

On December 8, 2020, the Utility entered into a settlement in the form of a consent judgment with the Central Coast Regional Water Quality Control Board regarding the thermal component of the plant's once-through cooling discharge. After a 30 day public comment period, the consent judgment was filed in San Luis Obispo Superior Court and the judgment was entered on May 25, 2021. The consent judgment includes payment of $5.9 million to the Central Coast Regional Water Quality Control Board to fund water quality improvement projects selected by the board.

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)	**June 30, 2021**	**December 31, 2020**
Topock natural gas compressor station	$ 295	$ 303
Hinkley natural gas compressor station	129	132
Former manufactured gas plant sites owned by the Utility or third parties [1]	681	659
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites [2]	112	111
Fossil fuel-fired generation facilities and sites [3]	75	96
Total environmental remediation liability	**$ 1,292**	**$ 1,301**

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

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

The Utility's environmental remediation liability at June 30, 2021, 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, the Utility's time frame for remediation, and unanticipated claims filed against the Utility. 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 June 30, 2021, the Utility expected to recover $999 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 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 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 $221 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. A draft background report was received in January 2020 and is expected to be finalized in 2022. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $137 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $400 million if the extent of contamination or necessary remediation at currently identified MGP sites 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 $53 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 $44 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.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL and EMANI, covering nuclear or non-nuclear events at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.5 billion per non-nuclear incident for Diablo Canyon. For Humboldt Bay Unit 3, NEIL provides up to $50 million of coverage for nuclear and non-nuclear property damages. NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Through NEIL, there is up to $3.2 billion available to the membership to cover this exposure. EMANI shares losses with NEIL, as part of the first $400 million of coverage within the current nuclear insurance program. EMANI also provides an additional $200 million in excess insurance for property damage and business interruption losses incurred by the utility if a nuclear or non-nuclear event were to occur at Diablo Canyon. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, the maximum aggregate annual retrospective premium obligation for the Utility would be approximately $42 million. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $4 million. For more information about the Utility's nuclear insurance coverage, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K.

Diablo Canyon Outages

Diablo Canyon Unit 2 experienced five outages between July 2020 and April 2021, each due or related to malfunctions within the main generator associated with excessive vibrations. Additional inspections and replacement of a redesigned component of the generator occurred during Unit 2's planned spring 2021 refueling outage. The affected component is part of the secondary system and does not involve a risk of release of radioactive material into the environment. During July 2020 through April 2021, the Utility implemented effective corrective actions. The Utility continues to monitor the affected component.

If additional shutdowns occur in the future, the Utility may incur incremental costs or forgo additional power market revenues. The Utility will also be subject to a review of the reasonableness of its actions before the CPUC.

Diablo Canyon carries property damage and outage insurance issued by NEIL and EMANI.

PG&E Corporation and the Utility do not currently believe that the resolution of this matter will have a material impact on their financial condition, results of operations, or cash flows.

Tax Matters

As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change, and consequently, its net operating loss carryforwards and other tax attributes are not limited by section 382 of the Internal Revenue Code.

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, 2020, the Utility had undiscounted future expected obligations of approximately $35 billion. (See Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K.)

Oakland Headquarters Lease and Sale of SFGO

On June 5, 2020, the Utility entered into an Agreement to Enter Into Lease and Purchase Option (the "Agreement") with TMG Bay Area Investments II, LLC ("TMG"). The Agreement provides that, contingent on (i) entry of an order by the Bankruptcy Court authorizing the Utility to enter into the Agreement and the Lease Agreement (as defined below), subject to certain conditions, and (ii) acquisition of the Lakeside Building by BA2 300 Lakeside LLC ("Landlord"), a wholly owned subsidiary of TMG, the Utility and Landlord will enter into an office lease agreement (the "Lease Agreement") for approximately 910,000 rentable square feet of space within the building located at the Lakeside Building to serve as the Utility's principal administrative headquarters (the "Lease"). On June 9, 2020, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court authorizing them to enter into the Agreement and grant related relief. The Bankruptcy Court entered an order approving the motion on June 24, 2020.

Pursuant to the terms of the Agreement, concurrent with the Landlord's acquisition of the building, on October 23, 2020, the Utility and the Landlord entered into the Lease, and the Utility issued to Landlord (i) an option payment letter of credit in the amount of $75 million on or before the Lease Date (as defined in the Agreement and the Lease Agreement), and (ii) a lease security letter of credit in the amount of $75 million.

The term of the Lease will begin on or about March 1, 2022. The Lease term will expire 34 years and 11 months after the commencement date, unless earlier terminated in accordance with the terms of the Lease. In addition to base rent, the Utility will be responsible for the costs and charges specified in the Lease, including insurance costs, maintenance costs and taxes.

The Lease requires the Landlord to pursue approvals to subdivide the real estate it owns surrounding the Lakeside Building to create a separate legal parcel that contains the Lakeside Building (the "Property") that can be sold to the Utility. The Lease grants to the Utility an option to purchase the Property, following such subdivision, at a price of $892 million, subject to certain adjustments (the "Purchase Price"). The Purchase Price would not be paid until 2023.

In connection with entry into the Agreement, the Utility intends to sell the SFGO. Any sale of the SFGO would be subject to approval by the CPUC. On September 30, 2020, the Utility filed an application with the CPUC seeking authorization to sell the SFGO. On April 21, 2021, the Utility entered into a settlement agreement with certain other parties and submitted the settlement agreement to the CPUC for approval. On May 26, 2021, the Utility filed an amended settlement agreement based on discussions with the presiding ALJ. Under the amended settlement, the parties agree that (1) the Utility's headquarters strategy, including the move to Oakland, the sale of SFGO, and the terms of the agreement to lease and the option to purchase the Lakeside Building, is reasonable, (2) all of the gain on sale of SFGO will be distributed to customers over five years, beginning in 2022, and (3) the costs associated with the Utility's move to the Lakeside Building and development will be considered at later stages of the proceeding and through a petition for modification of the final decision in the proceeding.

On May 21, 2021, the Utility entered into a purchase agreement (the "Purchase Agreement") with Hines Atlas US LP ("Hines"). The Agreement provides that, contingent on approval by the CPUC, the Utility will sell the SFGO to Hines. Under this agreement, the sale would take place 10 business days after CPUC approval of the sale but in no event prior to August 15, 2021. On July 22, 2021, the CPUC issued a PD approving the purchase agreement and the ratemaking treatment proposed under the parties' settlement. A final decision is expected on August 19, 2021. The purchase price will be $800 million subject to prorations and adjustments. Hines has deposited $20 million into escrow to serve as liquidated damages in the event of certain breaches by Hines.

At June 30, 2021, neither the Lease Agreement nor the Purchase Agreement had any impact on PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements.

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 Form 10-Q. It also should be read in conjunction with the 2020 Form 10-K.

Tax Matters

PG&E Corporation expects to have a U.S. federal net operating loss carryforward of approximately $28.1 billion and California net operating loss carryforward of $26.2 billion at the end of 2021.

Under section 382 of the Internal Revenue Code, if a corporation (or a consolidated group) undergoes an "ownership change," net operating loss carryforwards and other tax attributes may be subject to certain limitations. In general, an ownership change occurs if the aggregate stock ownership of certain shareholders (generally five percent shareholders, applying certain look-through and aggregation rules) increases by more than 50% over such shareholders' lowest percentage ownership during the testing period (generally three years). PG&E Corporation's and the Utility's Amended Articles limit Transfers (as defined in the Amended Articles) that increase a person's or entity's (including certain groups of persons) ownership of PG&E Corporation's equity securities to 4.75% or more prior to the Restriction Release Date without approval by the Board of Directors (the "Ownership Restrictions"). As discussed below under "Update on Ownership Restrictions in PG&E Corporation's Amended Articles," due to the agreement to treat the Fire Victim Trust as a "grantor trust" for U.S. federal income tax purposes, with the election, the calculation of Percentage Ownership (as defined in the Amended Articles) will effectively be based on a reduced number of shares outstanding, namely the total number of outstanding equity securities less the number of equity securities held by the Fire Victim Trust. As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change, and consequently, its net operating loss carryforwards and other tax attributes are not limited by section 382 of the Internal Revenue Code.

The tax deduction recorded on shares provided to the Fire Victim Trust under the Plan reflects PG&E Corporation's conclusion as of June 30, 2021 that it is more likely than not that the Fire Victim Trust would be treated as a "qualified settlement fund" for U.S. federal income tax purposes, in which case the corresponding tax deduction will have occurred at the time transfers of cash and other property (including PG&E Corporation common stock) were made to the Fire Victim Trust. In January 2021, PG&E Corporation received an IRS ruling that states the Utility is eligible to make a grantor trust election for U.S. federal income tax purposes with respect to the Fire Victim Trust and addressed certain, but not all, related issues. PG&E Corporation believed certain benefits associated with "grantor trust" treatment, including, a potentially larger tax deduction related to the proceeds realized by the Fire Victim Trust from the sale of shares transferred to the Fire Victim Trust, could be realized, but only if PG&E Corporation and the Fire Victim Trust could meet certain requirements of the Internal Revenue Code and Treasury Regulations thereunder, relating to sales of PG&E Corporation common stock. On April 29, 2021, the Bankruptcy Court entered an order approving the material terms of the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement. On July 8, 2021, PG&E Corporation, the Utility, ShareCo, and the Fire Victim Trust entered into the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement whereby PG&E Corporation and the Utility agreed to make a "grantor trust" election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

With the “grantor trust” election, the Utility’s tax deduction will occur at the time the Fire Victim Trust pays the fire victims and will be impacted by the price at which the Fire Victim Trust sells the shares, rather than the price at the time such shares were transferred to the Fire Victim Trust. Therefore, $5.4 billion of cash and $4.54 billion of PG&E Corporation common stock, in the aggregate $10.0 billion that was transferred to the Fire Victim Trust in 2020, will not be deductible for tax purposes until the Fire Victim Trust pays the fire victims. Consequently, PG&E Corporation’s net operating loss will decrease by approximately $10.0 billion. In addition, there will be a $1.3 billion charge, net of tax, decreasing net deferred tax assets for the payment made to the Fire Victim Trust in PG&E Corporation common stock on its Consolidated Financial Statements for activity through December 31, 2020. These adjustments are expected to be reflected in PG&E Corporation’s and the Utility’s quarterly report on Form 10-Q for the quarter ending September 30, 2021. PG&E Corporation will subsequently recognize income tax benefits and the corresponding deferred tax asset as the Fire Victim Trust sells the shares.

Update on Ownership Restrictions in PG&E Corporation’s Amended Articles

Because, as of July 8, 2021, PG&E Corporation and the Utility have agreed to treat the Fire Victim Trust as a “grantor trust” for U.S. federal income tax purposes as of July 8, 2021 (which treatment will be retroactive to the inception of the Fire Victim Trust), any shares owned by the Fire Victim Trust are effectively excluded from the total number of outstanding equity securities when calculating a person’s percentage ownership for purposes of the 4.75% ownership limitation in the Amended Articles. Shares owned by ShareCo are also effectively excluded because it is a disregarded entity for tax purposes. For example, although PG&E Corporation had 2,463,016,638 shares outstanding as of July 26, 2021, only 1,507,529,458 shares (the number of outstanding shares of common stock less the number of shares held by the Fire Victim Trust and ShareCo) count as outstanding for purposes of the ownership restrictions in the Amended Articles. As such, based on the total number of outstanding equity securities and assuming the Fire Victim Trust has not sold any shares of PG&E Corporation common stock, a person’s effective percentage ownership limitation for purposes of the Amended Articles as of July 26, 2021 was 2.9%. On July 8, 2021, the Fire Victim Trust disclosed that it held $5.8 billion in cash and investments of United States Treasury bills. It also disclosed that it had distributed $436.4 million to victims. As of July 26, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock.

Summary of Changes in Net Income (Loss) and Earnings per Share

PG&E Corporation’s net income was $397 million and $517 million for the three and six months ended June 30, 2021, respectively, compared to net losses of $1,972 million and $1,601 million in the same periods in 2020. In the three and six months ended June 30, 2020, PG&E Corporation recognized $1.1 billion of expense related to the shares issued to Backstop Parties pursuant to the Backstop Commitment Letters (the “Backstop Commitment Premium Shares”) and $444 million of expense related to the additional shares issued to the Backstop Parties pursuant to the Forward Stock Purchase Agreements (the “Additional Backstop Commitment Premium Shares”), with no similar amounts for the same periods in 2021. These amounts are partially offset by increases in base revenues authorized in the 2020 GRC and 2019 GT&S rate cases in the three and six months ended June 30, 2021.

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 Uncertainties in Connection with Any Future Wildfires, Wildfire Insurance, and AB 1054.* While PG&E Corporation and the Utility cannot predict the occurrence, timing or extent of damages in connection with future wildfires, factors such as environmental conditions (including weather and vegetation conditions) and the efficacy of wildfire risk mitigation initiatives are expected to influence the frequency and severity of future wildfires. To the extent that future wildfires occur in the Utility's service territory, the Utility may incur costs associated with the investigations of the causes and origins of such fires, even if it is subsequently determined that such fires were not caused by the Utility's facilities. The financial impact of future wildfires could be mitigated through insurance, the Wildfire Fund or other forms of cost recovery. However, the Utility may not be able to obtain sufficient wildfire insurance coverage at a reasonable cost, or at all, and any such coverage may include limitations that could result in substantial uninsured losses depending on the amount and type of damages resulting from covered events. Various coverage limitations applicable to different insurance layers could result in material uninsured costs in the future depending on the amount and type of damages resulting from covered events. The Utility will not be able to obtain any recovery from the Wildfire Fund for wildfire-related losses in any year that do not exceed the greater of $1.0 billion in the aggregate and the amount of insurance coverage required under AB 1054. In addition, the policy reforms contemplated by AB 1054 are likely to affect the financial impact of future wildfires on PG&E Corporation and the Utility should any such wildfires occur. The Wildfire Fund is available to the Utility to pay eligible claims for liabilities arising from future wildfires and serves as an alternative to traditional insurance products, provided that the Utility satisfies the conditions to the Utility's ongoing participation in the Wildfire Fund set forth in AB 1054 and that the Wildfire Fund has sufficient remaining funds. (See "Insurance Coverage" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

  However, the impact of AB 1054 on PG&E Corporation and the Utility is subject to numerous uncertainties, including the Utility's ability to demonstrate to the CPUC that wildfire-related costs paid from the Wildfire Fund were just and reasonable, and whether the benefits of participating in the Wildfire Fund ultimately outweigh its substantial costs. Finally, even if the Utility satisfies the ongoing eligibility and other requirements set forth in AB 1054, for eligible claims against the Utility arising from wildfires that occurred between July 12, 2019 and the Utility's emergence from Chapter 11 on July 1, 2020, the availability of the Wildfire Fund to pay such claims would be capped at 40% of the allowed amount of such claims. (See "Wildfire Fund under AB 1054" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Uncertainties Regarding the Impact of Public Safety Power Shutoffs*. The Utility's wildfire risk mitigation initiatives involve substantial and ongoing expenditures and could involve other costs. The extent to which the Utility will be able to recover these expenditures and potential other costs through rates is uncertain. The PSPS program, one of the Utility's wildfire risk mitigation initiatives included in the 2020-2022 WMP, has been the subject of significant scrutiny and criticism by various stakeholders, including the California governor, the CPUC and the court overseeing the Utility's probation. The PSPS program has had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers, and future PSPS events may increase these negative perceptions. In addition to the 2019 PSPS events, the Utility initiated several PSPS events in the third and fourth quarters of 2020 and one in January 2021 and expects that additional PSPS events will be necessary in future years. (See "OII to Examine the Late 2019 Public Safety Power Shutoff Events" and "OIR to Examine Electric Utility De-energization of Power Lines in Dangerous Conditions" in "Regulatory Matters" below.)

- *The Costs and Execution of Other Wildfire Mitigation Efforts.* In response to the wildfire threat facing California, PG&E Corporation and the Utility have taken aggressive steps to mitigate the threat of catastrophic wildfires, the spread of wildfires should they occur and the impact of PSPS events. PG&E Corporation and the Utility incurred approximately $2.6 billion in connection with the 2019 WMP and incurred approximately $3.9 billion through June 30, 2021 in connection with the 2020-2022 WMP. Although the Utility may seek cost recovery for certain of these expenses and capital expenditures, the Utility has agreed in the Wildfires OII not to seek rate recovery of certain wildfire-related expenses and capital expenditures that it has incurred or will incur in the amount of $1.823 billion in future applications.

The Utility is subject to a number of legal and regulatory requirements related to its wildfire mitigation efforts, which require periodic inspections of electric assets and ongoing reporting related to this work. Although the Utility believes that it has complied substantially with these requirements, it is undertaking a review and has identified instances of noncompliance. The Utility intends to update the CPUC upon the completion of its review. The Utility could face fines, penalties, enforcement action, or other adverse legal or regulatory consequences for the late inspections or other noncompliance related to wildfire mitigation efforts.

While PG&E Corporation and the Utility are committed to taking aggressive wildfire mitigation actions, if additional requirements are imposed that go beyond current expectations, such requirements could have a substantial impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. For example, the Court overseeing the Utility's probation in connection with the Utility's federal criminal proceeding has imposed numerous obligations on the Utility related to its business and operations. The success of the Utility's wildfire mitigation efforts depends on many factors, including on whether the Utility is able to retain or contract for the workforce necessary to execute its wildfire mitigation actions. (See "U.S. District Court Matters and Probation" and "Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's financial results may be impacted by the timing and outcome of its FERC TO18 and TO19 rate cases, 2023 GRC, WMCE application, and its ability to timely recover costs not currently in rates, including costs already incurred and future costs tracked in its CEMA, WEMA, WMPMA, FRMMA, CPPMA, VMBA, WMBA, and RTBA. 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. The Utility's ability to seek cost recovery will also be limited as a result of the outcome of the Wildfires OII. (See Notes 4 and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and "Regulatory Matters" below.)

- *The Impact of Wildfires*. Claims related to the 2019 Kincade fire that were not satisfied in full as of the Effective Date were not discharged in connection with emerging from Chapter 11. On July 16, 2020, Cal Fire issued a press release stating that it had determined that "the Kincade fire was caused by electrical transmission lines owned and operated by Pacific Gas and Electric (PG&E)." On April 6, 2021, the Sonoma County District Attorney's Office charged the Utility with 5 felonies and 28 misdemeanors in connection with the 2019 Kincade fire. Accordingly, if PG&E Corporation or the Utility were determined to be liable for the 2019 Kincade fire, such liabilities could be significant and could exceed or be excluded from the amounts available under applicable insurance policies or the Wildfire Fund under AB 1054, which could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. As of June 30, 2021, PG&E Corporation and the Utility had recorded an aggregate liability of $800 million for claims in connection with the 2019 Kincade fire (before available insurance), which amount corresponds to the lower end of the range of reasonably estimable probable losses, but does not include all categories of potential damages and losses. If the Utility were to be convicted of certain charges in the criminal complaint, the Utility could be subject to material fines, penalties, and restitution, as well as non-monetary remedies such as oversight requirements, and accordingly the Utility currently believes that, depending on which charges it were to be convicted of, its total losses associated with the 2019 Kincade fire would materially exceed the $800 million aggregate liability that PG&E Corporation and the Utility have recorded. If the liability for the 2019 Kincade fire were to exceed $1.0 billion, the Utility may be eligible to make a claim to the Wildfire Fund under AB 1054 for such excess amount, subject to the 40% limitation on the allowed amount of claims arising before emergence from bankruptcy and the other limitations and requirements under AB 1054. As of June 30, 2021, the Utility had also recorded an insurance receivable for $430 million. However, the Utility does not expect that any of its liability insurance would cover restitution payments ordered by the court presiding over the criminal proceeding. (See "2019 Kincade Fire" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1 for more information.)

On October 9, 2020 Cal Fire informed the Utility that it had taken possession of Utility equipment as part of Cal Fire's ongoing investigation into the 2020 Zogg fire. On March 22, 2021, Cal Fire issued a press release with its determination that the 2020 Zogg fire was caused by a pine tree contacting electrical facilities. Cal Fire also indicated that its investigative report has been forwarded to the Shasta County District Attorney's Office, which is investigating the matter. Accordingly, if PG&E Corporation or the Utility were determined to be liable for the 2020 Zogg fire, such liabilities could be significant and could exceed or be excluded from the amounts available under applicable insurance policies or the Wildfire Fund under AB 1054, which could be expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. As of June 30, 2021, PG&E Corporation and the Utility had recorded an aggregate liability of $375 million for claims in connection with the 2020 Zogg fire (before available insurance), which amount corresponds to the lower end of the range of reasonably estimable probable losses, but does not include all categories of potential damages. As of June 30, 2021, the Utility had also recorded an insurance receivable for $327 million in connection with the 2020 Zogg fire. (For more information see "2020 Zogg Fire" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

There have been numerous wildfires in the Utility's service territory during 2020 and since the beginning of the 2021 wildfire season, including the 2021 Dixie fire and the 2021 Fly fire. If the Utility were alleged or determined to be a cause of one or more of these wildfires, this allegation or determination could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

- *The Impact of the COVID-19 Pandemic.* PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows have been and could continue to be significantly affected by the outbreak of COVID-19. The principal areas of near-term impact include liquidity, financial results and business operations, stemming primarily from the ongoing economic hardship of the Utility's customers, the moratorium on service disconnections for residential and small business customers and for eligible medium and large commercial and industrial customers, the CPUC's "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" and an observed reduction in non-residential electrical load. The Utility continues to monitor the overall impact of the COVID-19 pandemic; however, the Utility expects a significant impact on monthly cash collections as long as current circumstances persist. As of June 30, 2021, PG&E Corporation and the Utility had access to approximately $3.2 billion of total liquidity comprised of approximately $233 million of Utility cash, $74 million of PG&E Corporation cash and $2.9 billion of availability under the Utility and PG&E Corporation credit facilities. Other impacts of COVID-19 on PG&E Corporation and the Utility have included operational disruptions, workforce disruptions, both in personnel availability (including a reduction in contract labor resources) and deployment, delays in production and shipping of materials used in the Utility's operations, higher credit spreads and borrowing costs and could potentially also include a reduction in revenue due to the cost of capital adjustment mechanism and incremental financing needs. The Utility has established a memorandum account for tracking costs related to the CPUC's emergency authorization and order, which, as of June 30, 2021, was $39 million. The Utility intends to seek recovery of this balance in a future application, subject to CPUC reasonableness review. For more information on the impact of COVID-19 on PG&E Corporation and the Utility, see "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic." in Item 1A Risk Factors in Part I of the 2020 Form 10-K.

  PG&E Corporation and the Utility expect additional financial impacts in the future as a result of COVID-19. PG&E Corporation and the Utility continue to evaluate the overall impact of COVID-19 and their analysis is subject to change.

- *The Outcome of Other Enforcement, Litigation, and Regulatory Matters, and Other Government Proposals.* The Utility's financial results may continue to be impacted by the outcome of other current and future enforcement, litigation, and regulatory matters, including those described above as well as the outcome of the OII into PG&E Corporation's and the Utility's Safety Culture, the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, including the oversight of the Utility's probation and the potential recommendations by the Monitor, and potential penalties in connection with the Utility's wildfire mitigation plan and safety and other self-reports. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) In addition, the Utility's business profile and financial results could be impacted by the outcome of recent calls for municipalization of part or all of the Utility's businesses, offers by municipalities and other public entities to acquire the electric assets of the Utility within their respective jurisdictions and calls for state intervention, including the possibility of a state takeover of the Utility. PG&E Corporation and the Utility cannot predict the nature, occurrence, timing or extent of any such scenario, and there can be no assurance that any such scenario would not involve significant ownership or management changes to PG&E Corporation or the Utility, including by the state of California. Further, certain parties filed notices of appeal with respect to the Confirmation Order, including provisions related to the injunction contained in the Plan that channels certain pre-petition fire-related claims to trusts to be satisfied from the trusts' assets. There can be no assurance that any such appeal will not be successful and, if successful, that any such appeal would not have a material adverse effect on PG&E Corporation and the Utility.

- *The Uncertainties in Connection with the Enhanced Oversight and Enforcement Process.* On April 15, 2021, the CPUC placed the Utility in step 1 of the EOEP. As a result, the Utility will be subject to additional reporting requirements, monitoring, and oversight by the CPUC. (See "Enhanced Oversight and Enforcement Process" in "Enforcement and Litigation Matters" below.)

For more information about the risks that could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in this Form 10-Q and the 2020 Form 10-K. 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" above for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are unable to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for the three and six months ended June 30, 2021 and 2020. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) attributable to common shareholders for the three and six months ended June 30, 2021 and 2020:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2021**	**2020**	**2021**	**2020**
Consolidated Total	$ 397	$ (1,972)	$ 517	$ (1,601)
PG&E Corporation	(39)	(1,495)	(93)	(1,572)
Utility	$ 436	$ (477)	$ 610	$ (29)

PG&E Corporation's net loss primarily consists of income taxes and interest expense on long-term debt. PG&E Corporation's net loss for the three and six months ended June 30, 2020 also included reorganization items, net, including approximately $1.5 billion in expense related to the Backstop Commitment Premium Shares and the Additional Backstop Commitment Premium Shares.

Utility

The tables below show certain items from the Utility's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2021 and 2020. 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 energy procurement costs) and the corresponding revenues the Utility is authorized to collect to recover such costs do not impact earnings.

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

	Three Months Ended June 30, 2021			**Three Months Ended June 30, 2020**		
	Revenues/Costs:			Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 2,542	$ 1,409	$ 3,951	$ 2,303	$ 1,132	$ 3,435
Natural gas operating revenues	928	336	1,264	832	266	1,098
Total operating revenues	**3,470**	**1,745**	**5,215**	**3,135**	**1,398**	**4,533**
Cost of electricity	—	847	847	—	759	759
Cost of natural gas	—	187	187	—	134	134
Operating and maintenance	1,826	755	2,581	1,596	549	2,145
Wildfire-related claims, net of insurance recoveries	(5)	—	(5)	170	—	170
Wildfire Fund expense	118	—	118	173	—	173
Depreciation, amortization, and decommissioning	851	—	851	874	—	874
Total operating expenses	**2,790**	**1,789**	**4,579**	**2,813**	**1,442**	**4,255**
Operating income (loss)	**680**	**(44)**	**636**	**322**	**(44)**	**278**
Interest income	15	—	15	12	—	12
Interest expense	(342)	—	(342)	(189)	—	(189)
Other income, net	80	44	124	49	44	93
Reorganization items, net	(10)	—	(10)	(111)	—	(111)
Income before income taxes	$ 423	$ —	$ 423	$ 83	$ —	$ 83
Income tax provision (benefit) [1]			(17)			556
Net income (loss)			440			(473)
Preferred stock dividend requirement [1]			4			4
Income (Loss) Attributable to Common Stock			**$ 436**			**$ (477)**

[1] These items impacted earnings for the three months ended June 30, 2021 and 2020.

(in millions)	Six Months Ended June 30, 2021 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Six Months Ended June 30, 2020 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 4,911	$ 2,435	$ 7,346	$ 4,459	$ 2,016	$ 6,475
Natural gas operating revenues	1,825	760	2,585	1,696	668	2,364
Total operating revenues	**6,736**	**3,195**	**9,931**	**6,155**	**2,684**	**8,839**
Cost of electricity	—	1,437	1,437	—	1,304	1,304
Cost of natural gas	—	494	494	—	418	418
Operating and maintenance	3,560	1,352	4,912	3,059	1,051	4,110
Wildfire-related claims, net of insurance recoveries	167	—	167	170	—	170
Wildfire Fund expense	237	—	237	173	—	173
Depreciation, amortization, and decommissioning	1,739	—	1,739	1,729	—	1,729
Total operating expenses	**5,703**	**3,283**	**8,986**	**5,131**	**2,773**	**7,904**
Operating income (loss)	**1,033**	**(88)**	**945**	**1,024**	**(89)**	**935**
Interest income	17	—	17	28	—	28
Interest expense	(690)	—	(690)	(441)	—	(441)
Other income, net	169	88	257	97	89	186
Reorganization items, net	(12)	—	(12)	(204)	—	(204)
Income before income taxes	$ 517	$ —	$ 517	$ 504	$ —	$ 504
Income tax provision (benefit) [1]			(100)			526
Net income (loss)			617			(22)
Preferred stock dividend requirement [1]			7			7
Income (Loss) Attributable to Common Stock			**$ 610**			**$ (29)**

[1] These items impacted earnings for the six months ended June 30, 2021 and 2020.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the three and six months ended June 30, 2021 and 2020, 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 $335 million, or 11%, and increased by $581 million, or 9%, in the three and six months ended June 30, 2021, compared to the same periods in 2020, primarily due to an increase in base revenues authorized in the 2020 GRC and 2019 GT&S rate cases.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $230 million, or 14%, in the three months ended June 30, 2021, compared to the same period in 2020, primarily due to the recognition of previously deferred costs related to the following: approximately $100 million related to vegetation management, approximately $100 million related to residential uncollectibles authorized for recovery (see "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" below), and approximately $80 million of costs recorded in conjunction with interim rate relief associated with the WMCE application (see "Wildfire Mitigation and Catastrophic Events Costs Recovery Application" below), with no comparable costs in the same period in 2020. Additionally, the Utility also experienced an increase in insurance costs in the three months ended June 30, 2021. These increases were partially offset by clean-up and repair costs of $35 million relating to the 2019 Kincade fire incurred in the three months ended June 30, 2020, with few comparable costs during the same period in 2021.

The Utility's operating and maintenance expenses that impacted earnings increased by $501, or 16%, in the six months ended June 30, 2021, compared to the same period in 2020, primarily due to the recognition of previously deferred costs related to the following: approximately $400 million related to vegetation management, approximately $160 million of costs recorded in conjunction with interim rate relief associated with the WMCE application (see "Wildfire Mitigation and Catastrophic Events Costs Recovery Application" below), and approximately $100 million related to residential uncollectibles authorized for recovery (see "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" below), with no comparable costs in the same period in 2020. Additionally, the Utility also experienced an increase in insurance costs in the six months ended June 30, 2021. These increases were partially offset by $20 million in restoration and rebuild costs related to the 2018 Camp fire, clean-up and repair costs of $35 million relating to the 2019 Kincade fire incurred in the six months ended June 30, 2020, with few comparable costs during the same period in 2021.

Wildfire-related claims, net of insurance recoveries

Costs related to wildfires that impacted earnings decreased by $175 million, or 103%, in the three months ended June 30, 2021, compared to the same period in 2020. The Utility recognized pre-tax charges of $75 million related to the 2020 Zogg fire, offset by $80 million of probable insurance recoveries, in the three months ended June 30, 2021, as compared to $600 million in pre-tax charges related to the 2019 Kincade fire, partially offset by $430 million in insurance recoveries recognized in the three months ended June 30, 2020.

Costs related to wildfires that impacted earnings decreased by $3 million, or 2%, in the six months ended June 30, 2021, compared to the same period in 2020. The Utility recognized pre-tax charges of $175 million related to the 2019 Kincade fire and $100 million related to the 2020 Zogg fire, offset by $108 million of probable insurance recoveries, in the six months ended June 30, 2021, as compared to $600 million in pre-tax charges related to the 2019 Kincade fire, partially offset by $430 million in insurance recoveries recognized in the six months ended June 30, 2020.

Wildfire Fund expense

Wildfire Fund expense that impacted earnings decreased by $55 million, or 32% in the three months ended June 30, 2021, compared to the same period in 2020. During the quarter ended June 30, 2020, the Utility became eligible to participate in the Wildfire Fund and as a result recorded amortization and accretion expense, retroactive to the effective date of the Wildfire Fund, July 12, 2019, related to the Wildfire Fund coverage.

Wildfire Fund expense that impacted earnings increased by $64 million, or 37%, in the six months ended June 30, 2021, compared to the same period in 2020. Due to the Chapter 11 Cases, the Utility's participation in the Wildfire Fund was limited to 40% for the period from July 12, 2019 to June 30, 2020.

Depreciation, Amortization, and Decommissioning

There were no material changes in depreciation, amortization, and decommissioning expenses that impacted earnings for the periods presented.

Interest Income

There was no material change to interest income that impacted earnings for the periods presented.

Interest Expense

Interest expense that impacted earnings increased by $153 million, or 81%, and increased by $249 million, or 56%, in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020, primarily due to the issuance of new debt in connection with or subsequent to emergence from Chapter 11.

Other Income, Net

Other income, net increased by $31 million, or 63%, and increased by $72 million, or 74%, in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020, due to the decrease in the discount rate resulting in lower expenses on non-service pension costs.

Reorganization items, net

Reorganization items, net decreased by $101 million, or 91%, and $192 million, or 94%, in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020, primarily due to the Utility's emergence from Chapter 11 on July 1, 2020.

Income Tax Provision (Benefit)

Income tax provision decreased by $573 million, and decreased by $626 million in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020, primarily due to a write-off of a deferred tax asset associated with the decline in value of PG&E stock contributed into the Fire Victim's Trust for the three and six months ended June 30, 2020 with no comparable adjustment in the same periods in 2021.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	**2020**	**2021**	**2020**
Federal statutory income tax rate	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) in income tax rate resulting from:				
State income tax (net of federal benefit) [1]	0.6 %	228.4 %	(2.6) %	38.5 %
Effect of regulatory treatment of fixed asset differences [2]	(25.0) %	(85.9) %	(39.0) %	(37.9) %
Tax credits	— %	(2.3) %	(0.5) %	(0.7) %
Bankruptcy and Emergence	0.1 %	519.7 %	0.2 %	86.7 %
Other, net	(0.8) %	(12.6) %	1.6 %	(3.3) %
Effective tax rate	**(4.1)%**	**668.3 %**	**(19.3)%**	**104.3 %**

[1] Includes the effect of state flow-through ratemaking treatment.

[2] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs. For these temporary tax differences, the Utility recognizes the deferred tax impact in the current period and records offsetting regulatory assets and liabilities. Therefore, the Utility's effective tax rate is impacted as these differences arise and reverse. The Utility recognizes such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 2021 and 2020, the amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

Utility Revenues and Costs that Did Not Impact Earnings

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

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), fuel and associated transmission costs used in its own generation facilities, fuel and associated transmission costs supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. Cost of electricity also includes net sales (Utility owned generation and third parties) in the CAISO electricity markets. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) The Utility's total purchased power is driven by customer demand, net CAISO electricity market activities (purchases or sales), the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2021	2020	2021	2020
Cost of purchased power, net	$ 796	$ 712	$ 1,326	$ 1,185
Fuel used in generation facilities	51	47	111	119
Total cost of electricity	**$ 847**	**$ 759**	**$ 1,437**	**$ 1,304**

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 8 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 June 30,		**Six Months Ended June 30,**	
(in millions)	**2021**	**2020**	**2021**	**2020**
Cost of natural gas sold	$ 153	$ 102	$ 423	$ 355
Transportation cost of natural gas sold	34	32	71	63
Total cost of natural gas	**$ 187**	**$ 134**	**$ 494**	**$ 418**

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. If the Utility were to spend more than authorized amounts, these expenses could have an impact on 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 retained earnings, equity contributions from PG&E Corporation and long-term debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock and relies on short-term debt, including its revolving credit facilities, to fund temporary financing needs. On May 28, 2020, the CPUC approved a final decision in the Chapter 11 Proceedings OII, which, among other things, grants the Utility a temporary, five-year waiver from compliance with its authorized capital structure for the financing in place upon the Utility's emergence from Chapter 11.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, and fund equity contributions to the Utility, depends on the level of cash on hand, cash distributions received from the Utility, and PG&E Corporation's access to the capital and credit markets.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowings, including 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. The collateral posting provisions for some of the Utility's power and natural gas commodity, and transportation and service agreements state that if the Utility's credit ratings were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some or all of its net liability positions. The Utility's credit ratings fell below investment grade in January 2019, at which time the Utility was required to post additional collateral under its commodity purchase agreements. A further downgrade would not materially impact the collateral postings for procurement activity. (See Notes 8 and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1.).

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows have been and could continue to be significantly affected by the outbreak of COVID-19. The Utility continues to evaluate the overall impact of the COVID-19 pandemic; however, the Utility expects a significant impact on monthly cash collections as long as current circumstances persist, including the moratorium on service disconnections for residential and small business customers, as well as for medium and large commercial and industrial customers through September 30, 2021. The Utility's customer energy accounts receivable balances over 30 days outstanding as of June 30, 2021, were approximately $998 million, or $507 million higher as compared to the balance as of June 30, 2020. The Utility is unable to estimate the portion of the increase directly attributable to the COVID-19 pandemic. The Utility expects to continue experiencing an impact on monthly cash collections for as long as current COVID-19 circumstances persist.

The outbreak of COVID-19 and the resulting economic conditions and government orders have had and will continue to have a significant adverse impact on the Utility's customers and, as a result, these circumstances have and will continue to impact the Utility for an indeterminate period of time. Although the Utility is seeking regulatory relief to mitigate the impact of the consequences of the COVID-19 pandemic, there can be no assurance that any relief is forthcoming or that, if any relief measures are implemented, the timing that any such relief would impact the Utility. On April 16, 2020, the CPUC approved a resolution that authorizes utilities to establish memorandum accounts to track incremental costs associated with complying with the customer protections described within the resolution. On May 1, 2020, the Utility submitted an advice letter with the CPUC, describing all reasonable and necessary actions to implement emergency customer protections through April 16, 2021, which was subsequently updated on June 2, 2020, and July 15, 2020, to modify and clarify the filing based on CPUC guidance. On July 27, 2020, the CPUC approved the Utility's advice letter. In February and March 2021, the CPUC extended the moratorium on service disconnections to June 30, 2021. In addition, on April 19, 2021, the CPUC issued a final decision to implement a temporary moratorium on service disconnection for medium and large commercial and industrial customers through June 30, 2021. On June 30, 2021, the CPUC extended this moratorium through September 30, 2021. (See "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" below for more information.) On July 16, 2021, the California governor signed into law AB 135, which provides financing assistance to customer accounts in arrears. (See "Assembly Bill 135" below for more information.)

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

Sale of Transmission Tower Wireless Licenses

On February 16, 2021, the Utility granted to a subsidiary of SBA Communications Corporation (such subsidiary, "SBA") an exclusive license enabling SBA to sublicense and market wireless communications equipment attachment locations ("Cell Sites") on more than 700 of the Utility's electric transmission towers, telecommunications towers, monopoles, buildings or other structures (collectively, the "Effective Date Towers") to wireless telecommunication carriers ("Carriers") for attachment of wireless communications equipment, as contemplated by a Master Transaction Agreement (the "Transaction Agreement") dated February 2, 2021, between the Utility and SBA. Pursuant to the Transaction Agreement, the Utility also assigned to SBA license agreements between the Utility and Carriers for substantially all of the existing Cell Sites on the Effective Date Towers.

The exclusive license was granted pursuant to a Master Multi-Site License Agreement (the "License Agreement") between the Utility and SBA. The term of the License Agreement is for 100 years. The Utility has the right to terminate the license for individual Cell Sites for certain regulatory or utility operational reasons, with a corresponding payment to SBA. Pursuant to the License Agreement, SBA is entitled to the sublicensing revenue generated by new sublicenses of Cell Sites on the Effective Date Towers, subject to the Utility's right to a percentage of such sublicensing revenue.

The Utility and SBA also entered into a Master Transmission Tower Site License Agreement (the "Tower Site Agreement"), pursuant to which SBA received the exclusive rights to sublicense and market additional attachment locations on up to 28,000 of the Utility's other electric transmission towers to Carriers for attachment of wireless communications equipment. The Tower Site Agreement provides for a split of license fees from Carriers between the Utility and SBA. The Tower Site Agreement has a licensing period of up to 15 years, depending on SBA's achievement of certain performance metrics, and any sites licensed during such licensing period will continue to be subject to the Tower Site Agreement for the same term as the License Agreement.

In addition, the Utility and SBA entered into a Pipeline Cell Site Transaction Agreement pursuant to which the Utility and SBA established terms and conditions for adding additional cell sites under the License Agreement. Pipeline Cell Sites are locations where the Utility was in the process of locating a new Cell Site for a wireless carrier at the close of the transaction.

In exchange for the exclusive license and entry into the License Agreement, SBA agreed to pay the Utility a purchase price of $973 million. SBA paid the Utility $946 million of such purchase price at the closing pursuant to the Transaction Agreement, which also contemplates the post-closing assignment of additional specified Cell Sites to SBA upon the satisfaction of certain terms and conditions, for which SBA will make additional purchase price payments to the Utility. The closing settlement also reflected an adjustment for an estimated amount of payments received by the Utility from Carriers in the pre-closing period that are allocable to licenses in the post-closing period. The purchase price is subject to further adjustment pursuant to the terms of the Transaction Agreement through August 15, 2021.

The Utility recorded approximately $365 million of the $946 million sales proceeds as a financing obligation, as this portion of the proceeds for existing Cell Sites represents a sale of future revenues. The Utility recorded approximately $106 million of the $946 million sales proceeds as a contract liability (deferred revenue), as a portion of proceeds with respect to the sublicensing of Cell Sites, as well as the Tower Site Agreement represents an upfront payment for access to space on the Utility's assets. The Utility utilized a third-party discounted cash flow model based on business assumptions and estimates to determine the allocation of the purchase price between the financing obligation and deferred revenue. The financing obligation and deferred revenue are presented within Other non-current liabilities on the Condensed Consolidated Balance Sheets.

The Utility recorded the remaining approximately $475 million ($471 million of which was noncurrent) of the sale proceeds to regulatory liabilities, for the portion that is probable to be returned to customers in accordance with existing revenue sharing practices.

The financing obligation is amortized through Electric operating revenue and Interest expense on the Condensed Consolidated Statements of Income using the effective interest method and the deferred revenue balance is amortized through Electric operating revenue ratably over the 100-year term.

Equity Financings

On April 30, 2021, PG&E Corporation entered into an Equity Distribution Agreement with the Agents, the Forward Sellers and the Forward Purchasers, establishing an at the market equity distribution program, pursuant to which PG&E Corporation, through the Agents, may offer and sell from time to time shares of PG&E Corporation's common stock having an aggregate gross sales price of up to $400 million. The Equity Distribution Agreement provides that, in addition to the issuance and sale of shares of common stock by PG&E Corporation to or through the Agents, PG&E Corporation may enter into Forward Sale Agreements with the Forward Purchasers.

As of June 30, 2021, there was $400 million available under PG&E Corporation's at the market equity distribution program for future offerings. During the six months ended June 30, 2021, PG&E Corporation has not sold any shares pursuant to the Equity Distribution Agreement or any Forward Sale Agreement.

Debt Financings

In March 2021, the Utility issued $1.5 billion aggregate principal amount of 1.367% First Mortgage Bonds due March 10, 2023, $450 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031, and $450 million aggregate principal amount of 4.20% First Mortgage Bonds due June 1, 2041. The proceeds were used for (i) the prepayment of all of the $1.5 billion 364-day term loan facility (maturing June 30, 2021) outstanding under the Utility's term loan credit agreement, (ii) the repayment of all of the borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement and (iii) general corporate purposes.

In June 2021, the Utility issued $800 million aggregate principal amount of 3.0% First Mortgage Bonds due June 15, 2028. The proceeds were used for general corporate purposes, including the repayment of borrowings under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

Credit Facilities

At June 30, 2021, PG&E Corporation and the Utility had $500 million and $2.4 billion available under their respective $500 million and $6.5 billion credit facilities, including the Utility's term loan credit facility and Receivables Securitization Programs. The amount the Utility may borrow under the Receivables Securitization Program is limited to the lesser of the facility limit and the facility availability. The facility availability may vary based on the amount of accounts receivable that the Utility owns that are eligible for sale to the SPV and the portion of those accounts receivable that are sold to the SPV that are eligible for advances by the lenders under the Receivables Securitization Program from time to time.

For more information, see "Credit Facilities" in Note 5 to the Condensed Consolidated Financial Statements in Item 1.

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.

Subject to the dividend restrictions as described in Note 6 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 Form 10-K, any decision to declare and pay dividends in the future will be made at the discretion of the Boards of Directors and will depend on, among other things, results of operations, financial condition, cash requirements, contractual restrictions and other factors that the Boards of Directors may deem relevant. As of June 30, 2021, it is uncertain as to when PG&E Corporation and the Utility will commence the payment of dividends on their common stock and when the Utility will commence the payment of dividends on its preferred stock.

Utility Cash Flows

The Utility's cash flows were as follows:

	Six Months Ended June 30,	
(in millions)	**2021**	**2020**
Net cash provided by operating activities	$ 1,335	$ 2,800
Net cash used in investing activities	(3,568)	(3,441)
Net cash provided by financing activities	2,074	9,334
Net change in cash, cash equivalents and restricted cash	**$ (159)**	**$ 8,693**

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 six months ended June 30, 2021, net cash provided by operating activities decreased by $1.5 billion compared to the same period in 2020. This decrease was primarily due to the payment of $758 million to the Fire Victim Trust in accordance with the Plan, and payment for interest in the amount of $595 million, with no similar payments made during the same period in 2020. These payments were partially offset by $581 million of cash received from SBA related to a portion of the License Agreement and Tower Site Agreement, with no similar cash receipts in the same period in 2020, and by higher base revenue collections authorized in the 2020 GRC and 2019 GT&S rate cases.

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

- the timing and amount of costs in connection with the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire, and the timing and amount of related insurance recoveries;

- 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 Matters" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and "Regulatory Matters" below for more information);

- the severity, extent and duration of the global COVID-19 pandemic and its impact on the Utility's service territory, the ability of the Utility to collect on its customer invoices, the ability of the Utility's customers to pay their utility bills in full and in a timely manner, the ability of the Utility to offset these effects, including with spending reductions and the ability of the Utility to recover from customers any losses incurred in connection with COVID-19, as well as the impact of COVID-19 on the availability or cost of financing;

- the timing and amounts of annual contributions to the Wildfire Fund and if necessary, the availability of funds to pay eligible claims for liabilities arising from future wildfires;

- the timing and amount of substantially increasing costs in connection with 2020-2022 WMPs and the costs previously incurred in connection with the 2019 WMP that are not currently being recovered in rates (see "Regulatory Matters" below for more information);

- the timing and amount of premium payments related to wildfire insurance (see "Insurance Coverage" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1 for more information);

- the timing of the final payment to be made to the Fire Victim Trust, pursuant to the terms of the tax benefits payment agreement between the Fire Victim Trust and the Utility (see "Restructuring Support Agreement with the TCC" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1 for more information);

- the timing of and amount of the gain to be returned to customers from the sale of the SFGO and the purchase of the Lakeside Building; and

- the timing and outcomes of the Utility's pending and future ratemaking and regulatory proceedings, including the extent to which PG&E Corporation and the Utility are able to recover their costs through regulated rates as recorded in memorandum accounts or balancing accounts, or as otherwise requested.

Investing Activities

Net cash used in investing activities increased by $127 million during the six months ended June 30, 2021 as compared to the same period in 2020. The Utility's investing activities primarily consist of the construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur between $7.5 billion and $8.5 billion in capital expenditures in 2021 and between $7.8 billion and $8.9 billion in 2022. Additionally, future cash flows from investing activities will be impacted by the timing of and amount received from the proposed sale of the Utility's SFGO and the purchase of the Lakeside Building.

Financing Activities

Net cash provided by financing activities decreased by $7.3 billion during the six months ended June 30, 2021 as compared to the same period in 2020.

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 or prepayment date of existing debt instruments. Additionally, future cash flows from financing activities will be affected by the timing and outcome of the Utility's applications for a post-emergence securitization transaction and for a AB 1054 securitization transaction. (See "Application for Post-Emergence Securitization Transaction" and "Application for AB 1054 Securitization Transaction" below for more information.)

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Notes 10 and 11 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, liquidity, and cash flows. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2020 Form 10-K.

U.S. District Court Matters and Probation

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

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

On August 7, 2020, after a number of filings involving different parties, the court entered an order adopting the new conditions jointly proposed by the Utility, the Monitor, and the Department of Justice on June 24, 2020. Among other things, these conditions require the Utility to staff an in-house vegetation inspection manager and approximately 30 additional field inspectors to oversee vegetation management work. Further, the Utility is required to implement a program to assess the age and expected useful life of certain electrical components in high fire-threat areas, incorporate this information into its risk-based asset management programs and provide monthly progress reports to the Monitor. The Utility must also hire additional inspectors to oversee inspections of its transmission assets and implement a 90-day replacement requirement for cold end hardware in high fire-threat areas with an observed material loss approaching 50%.

On December 29, 2020, the court entered an order requiring the Utility to show cause as to why additional proposed conditions of probation should not be added. The proposed conditions would require the Utility to, when determining which distribution lines to de-energize during a PSPS event: (i) take into account the extent to which vegetation bordering those lines is not in compliance with certain requirements, and (ii) to the extent that information shows that such vegetation presents a safety hazard in the event of a windstorm, make a specific determination with respect to that distribution line and de-energize it unless the Utility finds in writing that there are specific reasons to believe that no safety issues exist. The Utility filed its response on January 20, 2021, proposing supplemental language to clarify and specify how the Utility will implement the new conditions proposed by the court. On March 24, 2021, the court issued an order requiring the Utility to provide, among other information, a revision of the proposed conditions of probation that incorporates consideration of the potential for a tree to fall into an overhead electric line based on its height and distance from the line. On April 29, 2021, the court entered an order declining to impose these proposed conditions, but recommending that the Utility, when determining which distribution lines to de-energize during a PSPS event: (i) take into account the extent to which vegetation bordering those lines is not in compliance with certain requirements, and (ii) to the extent that information shows that such vegetation presents a safety hazard in the event of a windstorm, make a specific determination with respect to that distribution line and de-energize it unless the Utility finds in writing that there are specific overriding public safety needs to leave the lines energized. The court also ordered the Utility to file a statement by July 1, 2021 setting forth its PSPS criteria for 2021 and stating the extent to which it has adopted the court's recommendations. The Utility submitted its response on July 1, 2021.

On February 4, 2021, the court entered an order requiring the Utility to show cause as to why the additional proposed conditions of probation suggested by amici in a January 27, 2021 filing should not be added. The proposed conditions would require the Utility to: (i) hire a chief data operations officer with the responsibility to review the Utility's information management and record-keeping systems and manage the relationship to operations, including vegetation management work and PSPS; (ii) initiate steps to prevent data falsification or omission; (iii) propose a plan to mark trees in tier 2 and tier 3 high wildfire danger zones for removal and track the status of the tree removal process for vegetation management; and (iv) propose steps to improve its information management and records-keeping process to improve information integrity, inform analysis, and inform and enhance daily operations including PSPS. The Utility's and the United States' responses were submitted on March 3, 2021, and reply by amici was submitted on March 10, 2021.

On February 18, 2021, the court issued an order requiring the Utility to show cause as to why an additional proposed condition of probation, which would require the Utility to "identify and remove any tree or portion thereof leaning toward any distribution line if it may contact the line from the side or fall on the line and must do so *regardless of the health of the tree[,]*" should not be added. On April 29, 2021, the court modified the Utility's conditions of probation to require the Utility to comply with the scope of section 4293 of the California Public Resources Code as articulated by the CPUC and Cal Fire.

On April 20, 2021, the court issued an order requiring the Utility to appear in connection with a potential probation violation based on the charges filed by the Sonoma County District Attorney's office related to the 2019 Kincade fire. The court held hearings on May 4, 2021 and June 2, 2021. The court continued the matter until September 13, 2021.

In the course of 2021, the court entered numerous other orders, including in connection with the Utility's vegetation management, the Utility's PSPS program, the 2018 Camp fire, the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire.

The Utility may receive additional orders from the court for the duration of the probation period in the future.

Enhanced Oversight and Enforcement Process

In the OII to Consider PG&E Corporation's and the Utility's Plan of Reorganization final decision, the CPUC adopted an EOEP designed to provide a roadmap for how the CPUC will monitor the Utility's performance on an ongoing basis. The EOEP contains six steps that are triggered by specific events and includes enhanced reporting requirements and additional monitoring and oversight. These trigger events include failure to obtain an approved WMP, failure to comply with regulatory reporting requirements in the WMP, insufficient progress toward approved safety or risk-driven investments and failure to comply with or demonstrate sufficient progress toward certain metrics (some of which will be determined in an ongoing regulatory proceeding). The EOEP also contains provisions for the Utility to cure and permanently exit the EOEP if it can satisfy specific criteria. If the Utility is placed into the EOEP, actions taken would occur in coordination with the CPUC's existing formal and informal reporting requirements and procedures. The EOEP does not replace or limit the CPUC's regulatory authority, including the authority to issue Orders to Show Cause and Orders Instituting Investigations and to impose fines and penalties. The EOEP requires the Utility to report the occurrence of a triggering event to the CPUC's Executive Director no later than five business days after the date on which any member of senior management of the Utility becomes aware of the occurrence of a triggering event.

The Utility is unable to predict whether additional fines or penalties may be imposed, or other regulatory actions may be taken.

Vegetation Management

On April 15, 2021, the CPUC placed the Utility into step 1 of the EOEP and will impose additional reporting requirements on the Utility. The CPUC's resolution states that a step 1 triggering event has occurred because the Utility "has made insufficient progress toward approved safety or risk-driven investments related to its electric business." The resolution finds that, based on the CPUC's evaluation of the Utility's enhanced vegetation management work in 2020, the Utility "is not sufficiently prioritizing its Enhanced Vegetation Management (EVM) based on risk" and "is not making risk-driven investments." The resolution also finds that "less than five percent of the EVM work" the Utility completed in 2020 "was on the 20 highest risk power lines according to [its] own risk rankings."

As required by the CPUC's resolution, the Utility submitted a corrective action plan to the CPUC's executive director on May 6, 2021, which is designed to correct or prevent recurrence of the step 1 triggering event, or otherwise mitigate any ongoing safety risk or impact, as soon as practicable, among other things. The corrective action plan addresses the EVM situation that occurred in 2020 and provides a risk-informed EVM workplan for 2021. The Utility is required to update the information contained in the corrective action plan every 90 days. The Utility will remain in step 1 of the EOEP until the CPUC determines that the Utility has met the conditions of the corrective action plan. If the Utility does not adequately meet such conditions within the timeframe approved by the CPUC, the CPUC may place the Utility into a higher step of the EOEP, or the Utility may remain in step 1 of the EOEP if it demonstrates sufficient progress towards meeting such conditions.

The Utility is unable to predict the outcome of this regulatory process.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of the proceedings described below, and other proceedings may materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Discussed below are significant regulatory developments that have occurred since filing the 2020 Form 10-K.

Periodically, costs arise that could not have been anticipated by the Utility during GRC applications or that have been deliberately excluded therefrom. These costs may result from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account, and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. The CPUC has also authorized balancing accounts with limitations or caps to cost recovery. These accounts, which include the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, and RTBA among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. While the Utility expects such costs to be recoverable, there can be no guarantee that the CPUC will authorize the Utility to recover the full amount of its costs, or the Utility may enter into a settlement for an amount that is less than the full amount of its costs.

In recent years, the amount of the costs recorded in these accounts has increased. As of June 30, 2021, the Utility had recorded an aggregate amount of approximately $3.4 billion in the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, and RTBA. Because rate recovery requires CPUC authorization in separate proceedings for these accounts, there is a delay between when the Utility incurs costs and when it may recover those costs.

If the amount of the costs recorded in these accounts continues to increase, the delay between incurring and recovering costs lengthens, or the Utility does not recover the full amount of its costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected.

(For more information, see Note 4 of the Notes to the Condensed Consolidated Financial Statements in Item 1., "Regulatory Matters - Wildfire Mitigation and Catastrophic Events Costs Recovery Application," "Regulatory Matters - Application for Recovery of Costs Recorded in the Wildfire Expense Memorandum Account," "Regulatory Matters - Catastrophic Event Memorandum Accounts and Applications," and "Regulatory Matters - Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" below.)

2023 General Rate Case

On June 30, 2021, the Utility filed its 2023 GRC application with the CPUC. In the 2023 GRC, the CPUC will determine the annual amount of base revenues that the Utility will be authorized to collect from customers from 2023 through 2026 to recover its anticipated costs for gas distribution, transmission and storage, electric distribution, and electric generation and to provide the Utility an opportunity to earn its authorized rate of return. The Utility's revenue requirements for other portions of its operations, such as electric transmission, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.

In a GRC, the CPUC approves annual revenue requirements for the first year (a "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). For its 2023 test year, the Utility has requested revenue requirements of $15.46 billion, an increase of $3.56 billion over the adopted 2020 GRC and 2019 GT&S revenue requirements for 2022 of $11.90 billion. The GRC application further states that the Utility's requested 2023 revenue requirements represent a 9.6% increase over its total revenue requirements for 2022 (including both amounts that are authorized and that are requested outside of the GRC and remain subject to the regulatory process). The requested weighted-average GRC rate base for 2023 is approximately $48.52 billion, which corresponds to an increase of $9.35 billion over the authorized rate base for 2022 of $39.17 billion. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized GRC revenues in 2024, 2025, and 2026 by $930 million, $590 million, and $381 million, respectively. The Utility estimates its proposed revenue requirements for 2024, 2025, and 2026 would result in revenue requirement increases of 2.4%, 1.9%, and 1.5%, compared to its total estimated revenue requirements for 2023, 2024, and 2025, respectively. Over the 2023-2026 GRC period, the Utility plans to make average annual capital investments of approximately $7.75 billion in gas distribution, transmission and storage, electric distribution, and electric generation infrastructure, and to improve safety, reliability, and customer service.

The following table compares the requested revenue requirements for 2023 with the comparable revenue requirements currently authorized for 2022, by both line of business and cost category:

Line of Business [(1)] (in millions)	**Amounts requested in the 2023 GRC application**	**Amounts currently authorized for 2022** [(2)]	**Requested increase compared to currently authorized amounts**
Gas distribution	$ 2,870	$ 2,321	$ 550
Gas transmission and storage	1,989	1,662	327
Electric distribution	8,171	5,514	2,657
Electric generation	2,431	2,404	26
Total revenue requirements	**$ 15,461**	**$ 11,901**	**$ 3,560**

(1) May not sum due to rounding.
(2) These amounts include revenues from Decision (D.) 20-12-005 (the Utility's 2020 GRC), D.19-09-025 (the Utility's 2019 GT&S) adjusted for D.19-12-056 and Advice Letter (AL) 4275-G/5887-E (Cost of Capital changes adopted for Long Term Debt and Common Stock) and AL 4367-G/6062-E (Excess Accumulated Deferred Income Taxes Pursuant to the 2017 Tax Act). Also included are the 2022 adopted revenue requirements associated with the following previously separately-funded projects: AL 5322-E (Energy Storage), D.16-12-065 (Electric Vehicle Charging Network Phase I), D.14-03-021 (Mobile Home Park to the Meter), D.20-11-035 (2019 CEMA), AL 4392-G/6100-E (Wildfire Mitigation Balancing Account and Vegetation Management Balancing Account), AL 4444-G/6210-E (Risk Transfer Balancing Account).

In the 2023 GRC application, the Utility proposes a series of safety, resiliency, and clean energy investments to further reduce wildfire risk and deliver safe, reliable, and clean energy service. Among other things, the Utility proposes to invest a total of approximately $31.00 billion between 2023 and 2026 to reduce wildfire risk; improve gas and electric system safety, reliability, and resiliency; increase the use of new, innovative technologies; and expand its clean energy infrastructure.

In addition to coverage that may be available from the private insurance market, the Utility also proposes to use self-insurance as part of its wildfire insurance program as follows: (1) the Utility's recommended approach, a new self-insurance structure whereby the Utility would seek customer-funded self-insurance in the amount of $250 million annually and traditional private insurance procurement for amounts between the accumulated self-insurance balance and $1.0 billion; or, alternatively (2) continuing the currently authorized mechanism whereby the Utility seeks procurement of wildfire liability insurance instruments through the private insurance market and is authorized to use any unspent authorized revenue requirements on self-insurance.

In addition, the Utility requests authorization to establish one new balancing account and one new memorandum account as follows:

- Catastrophic Events Straight-Time Labor Balancing Account, a two-way account which would recover straight-time labor costs associated with catastrophic events. These costs are currently recovered through the Catastrophic Events Memorandum Account process.

- Helms Capacity Memorandum Account, which would allow the Utility to track and recover the actual costs associated with upgrading the Helms Pumped Storage Facility through a future application.

The Utility is not seeking recovery of compensation of PG&E Corporation's and the Utility's officers within the scope of 17 Code of Federal Regulations 240.3b-7.

On March 24, 2021, TURN submitted a proposal that would require the Utility to provide an alternative forecast in the 2023 GRC corresponding to the rate of inflation. On July 16, 2021, the CPUC adopted a decision denying TURN's proposal.

In its application, in accordance with the CPUC's standard Rate Case Plan schedule, the Utility requests that the CPUC issue a proposed decision by December 19, 2022. It also requests that the 2023 GRC rates be effective January 1, 2023. The Utility expects a prehearing conference to be held in August 2021 to set a procedural schedule, including the dates for interested parties to submit testimony and for evidentiary hearings.

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

Wildfire Mitigation and Catastrophic Events Costs Recovery Application

On September 30, 2020, the Utility filed an application with the CPUC requesting cost recovery of recorded expenditures related to wildfire mitigation, certain catastrophic events, and a number of other activities (the "WMCE application"). The recorded expenditures, which exclude amounts disallowed as a result of the CPUC's decision in the OII into the 2017 Northern California wildfires and the 2018 Camp fire, consist of $1.18 billion in expense and $801 million in capital expenditures, resulting in a proposed revenue requirement of approximately $1.28 billion.

The costs addressed in the WMCE application cover activities mainly during the years 2017 to 2019 and are incremental to those previously authorized in the Utility's 2017 GRC and other proceedings. The majority of costs addressed in this application reflect work necessary to mitigate wildfire risk and to respond to catastrophic events occurring during the years 2017 to 2019. The Utility's requested revenue includes amounts for the FHPMA of $293 million, the FRMMA and the WMPMA of $740 million, and the CEMA of $251 million. The requested revenue for CEMA costs reflected in the application include the Utility's costs incurred responding to ten catastrophic events.

Given the CPUC's prior approval of $447 million in interim rate relief (which includes interest), the Utility proposed to recover the remaining $868 million revenue requirement, including interest, over a one-year period (following the conclusion of interim rate relief recovery). Cost recovery requested in this application is subject to the CPUC's reasonableness review, which could result in some or all of the interim rate relief of $447 million being subject to refund.

Hearings were held in June 2021. Opening briefs were filed July 23, 2021 and reply briefs are to be filed on August 6, 2021. The scoping memo and ruling for the proceeding calls for a PD to be issued in September 2021.

The Utility is unable to predict the outcome of this application. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs included in this application.

For more information regarding the FHPMA, the FRMMA, the WMPMA, and the CEMA memorandum accounts, see Note 4 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and the 2020 Form 10-K.

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

On February 7, 2020, the Utility filed an application seeking recovery of certain costs recorded in the WEMA. In the application, the Utility seeks recovery of $498.7 million for the cost of insurance premiums paid by the Utility between July 26, 2017 through December 31, 2019 that is incremental to the insurance costs already authorized in the 2017 GRC or the 2020 GRC. These incremental costs are not associated with any specific wildfire event. The application does not seek recovery of wildfire claims or associated legal costs eligible for recording to WEMA.

On January 12, 2021, the CPUC issued a scoping memo establishing the scope and schedule for the proceeding. On February 26, 2021, parties served testimony addressing the Utility's application. The Utility served rebuttal testimony on March 19, 2021. On June 30, 2021, the Utility and other parties filed a joint motion for approval of a settlement agreement, which, if adopted, would authorize recovery of a $445.4 million revenue requirement.

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

For more information see Note 4 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

Catastrophic Event Memorandum Accounts and 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. In the 2020 GRC Decision, the CPUC required the Utility to track these costs in the VMBA beginning January 1, 2020. The Utility's CEMA applications are subject to CPUC review and approval. For more information see Note 4 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections

In response to the COVID-19 pandemic, on April 16, 2020, the CPUC adopted a resolution ordering utilities to implement a number of emergency customer protections for one year beginning on March 4, 2020 through April 16, 2021.

The resolution also authorizes utilities to establish memorandum accounts to track incremental costs associated with complying with the resolution.

On June 11, 2020, the CPUC issued a final decision as part of the OIR to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs that permanently eliminated deposit requirements for residential customers. On April 19, 2021, the CPUC issued a final decision to implement a temporary moratorium on service disconnection for medium and large commercial and industrial customers through June 30, 2021. To be eligible, medium or large commercial or industrial customers must be enrolled in and current on a payment plan by June 30, 2021. The final decision authorized the Utility to submit an advice letter to establish a memorandum account to track incremental costs for the period of December 30, 2020 to June 30, 2021 for this moratorium. The Utility submitted the advice letter on May 14, 2021. On June 30, 2021, the Commission issued a final decision on bill debt relief, which further suspended disconnections to September 30, 2021 for residential and small business customers (which was extended to medium and large customers as well by an existing decision).

PG&E Corporation and the Utility are unable to predict whether this resolution will be further extended, which could have a material impact on results of operations, financial condition, and cash flows of PG&E Corporation and the Utility.

For more information, see the 2020 Form 10-K.

Other Regulatory Proceedings

Application to Sell General Office Complex

On September 30, 2020, the Utility filed an application with the CPUC to sell its SFGO located at 25 Beale Street, 45 Beale Street, 77 Beale Street, 50 Main Street, 215 Market Street and 245 Market Street in downtown San Francisco, and to recover costs to relocate its staff at SFGO to a new headquarters to the Lakeside Building, and for appropriate ratemaking treatment of those transactions.

The Utility proposes the SFGO sale and headquarters transition proceed in several interrelated steps: the Utility has entered into a lease for the Lakeside Building with an option to purchase the Lakeside Building; the Utility will market and sell the SFGO, subject to CPUC approval; and the Utility will enter into an agreement with the buyer of the SFGO to lease back space during the multi-year relocation period (collectively, the "Transactions"). As space in the Lakeside Building becomes available following the expiration of existing tenants' leases and completion of the redevelopment of the property to the Utility's specifications, the Utility will relocate employees and operations from the SFGO and certain East Bay office locations to the Lakeside Building in phases over several years, beginning in 2022.

In this application, the Utility requests that the CPUC: (i) authorize the Utility to sell the SFGO pursuant to Public Utilities Code section 851, (ii) approve the Utility's ratemaking proposal to distribute all of the gain on sale of the SFGO to customers over five years, beginning in 2022, (iii) approve the recovery of costs to lease back the SFGO after the buildings are sold, costs to lease the Lakeside Building, and other transition costs, and (iv) authorize the Utility to forecast the intended purchase of the Lakeside Building and include it in the Utility's 2023 GRC. The Utility also proposes to establish a balancing account to record lease payments, net savings or costs on operating expense and capital expense, gain on sale, moving costs and related costs for inclusion in electric and gas rates.

On December 15, 2020, the assigned commissioner issued a scoping memo, which contemplates a CPUC final decision as early as August 2021 and provides for additional timeline flexibility depending on the pace of the sale process. On April 21, 2021, the Utility entered into a settlement agreement with certain other parties and submitted the settlement agreement to the CPUC for approval. On May 26, 2021, the Utility filed an amended settlement agreement based on discussions with the presiding ALJ. Under the amended settlement, the parties agree that (1) the Utility's headquarters strategy, including the move to the Lakeside Building, the sale of SFGO, and the terms of the agreement to lease and the option to purchase the Lakeside Building, is reasonable, (2) all of the gain on sale of SFGO will be returned to customers over five years, beginning in 2022, and (3) the costs associated with the Utility's move to the Lakeside Building and development will be considered at later stages of the proceeding and through a petition for modification of the final decision in the proceeding.

On May 21, 2021, the Utility entered into a purchase agreement with Hines Atlas US LP, to sell the SFGO for $800 million. The sale under the agreement would take place 10 business days after CPUC approval of the sale but in no event prior to August 15, 2021. On June 11, 2021, the Utility served testimony in the CPUC proceeding regarding the SFGO sale terms.

On July 22, 2021, the CPUC issued a PD approving the purchase agreement and the ratemaking treatment proposed under the parties' settlement. A final decision is expected on August 19, 2021.

Application for Post-Emergence Securitization Transaction

On April 30, 2020, the Utility filed an application with the CPUC seeking authorization for a post-emergence transaction to recover $7.5 billion of 2017 wildfire claims costs through securitization that is designed to be rate neutral to customers, with the proceeds used to pay or reimburse the Utility for the payment of wildfire claims costs associated with 2017 Northern California wildfires. Among other uses, as a result of the proposed transaction, the Utility would retire $6.0 billion of Utility debt and accelerate a $592 million payment due to the Fire Victim Trust. Specifically, the application requested administration of the stress test methodology approved in the CHT OIR and a determination that $7.5 billion in 2017 catastrophic wildfire costs and expenses are stress test costs and eligible for securitization. In this context, a securitization refers to a financing transaction where a special purpose financing vehicle issues new debt that is secured by the proceeds of a new recovery charge to Utility customers. The application also proposed a customer credit designed to equal the bond charges over the life of the bonds, which would insulate customers from the charge on customer bills associated with the bonds. The Utility initially proposed to fund the customer credit through a trust that consists of shareholder assets including: (1) an initial contribution of $1.8 billion; (2) up to $7.59 billion of additional contributions funded by certain shareholder tax benefits; and (3) investment returns on the assets in the trust. The Utility also proposed to share with customers 25% of any surplus of shareholder assets in the customer credit trust at the end of the life of the trust.

On January 15, 2021, the Utility made an alternative proposal for the CPUC's consideration comprised of four elements: (1) a $200 million increase in the initial shareholder contribution, from $1.8 billion to $2 billion, provided that $1 billion is contributed in 2021 and up to $1 billion in 2024; (2) potential shift in the customer credit trust's investment portfolio to a greater proportion of fixed income investments; (3) a single CPUC review of the balance of the customer credit trust in 2040, with a single contingent supplemental shareholder contribution, if needed, up to $775 million in 2040; and (4) a reduced sharing of any trust surplus with customers to 10%.

On March 23, 2021, the ALJ issued a PD finding that $7.5 billion of the Utility's 2017 catastrophic wildfire costs and expenses are stress test costs that may be financed through the issuance of recovery bonds pursuant to Public Utilities Code sections 850 *et seq.* and approving a structure for the transaction. The PD generally adopts the transaction structure proposed by the Utility and authorizes the Utility to establish a customer credit trust funded by PG&E Corporation's shareholders, that will provide a monthly customer credit to customers that is anticipated to equal the securitized charges such that the securitization is designed to be rate neutral to customers. The PD also implements elements (1) through (3) of the Utility's alternative proposal described above, and as to (4) the PD maintains a 25% sharing of any trust surplus with customers. On April 21, 2021, the CPUC issued a revised PD incorporating certain clarifications based on parties' comments, and on April 22, 2021, the CPUC approved the revised PD. Three parties filed applications for rehearing of the decision on May 3, 2021, and the Utility filed a response to those applications on May 14, 2021.

Separately, on January 6, 2021, the Utility filed an additional application requesting that the CPUC issue a financing order authorizing the issuance of one or more series of recovery bonds in connection with the post-emergence transaction to securitize the $7.5 billion of claims associated with the 2017 Northern California wildfires. On April 5, 2021, the ALJ issued a PD granting the Utility's January 2021 application for a financing order authorizing the issuance of $7.5 billion of recovery bonds in connection with the rate neutral securitization proceeding. On May 4, 2021, the CPUC issued a revised PD incorporating certain clarifications based on parties' comments, and on May 6, 2021, the CPUC approved the revised PD. Two parties filed applications for rehearing of the financing order, and the Utility filed a response to those applications for rehearing on June 4, 2021.

Application for AB 1054 Securitization Transaction

On February 24, 2021 the Utility filed an application with the CPUC seeking authorization for a transaction to securitize up to $1.19 billion of fire risk mitigation capital expenditures that were or will be incurred by the Utility in 2020 and 2021. The $1.19 billion reflects capital expenditures related to the Utility's Community Wildfire Safety Program that were approved by the CPUC in the 2020 GRC, and includes $655 million in recorded 2020 capital expenditures and an additional $535 million in forecast capital expenditures in 2021. The final amount to be securitized would be based on recorded 2020 and 2021 Community Wildfire Safety Program capital expenditures incurred by the Utility prior to the securitization transaction.

The application requested that the CPUC issue a financing order authorizing one or more series of recovery bonds, determine that the issuance of the bonds and collection through fixed recovery charges is just and reasonable, consistent with the public interest and would reduce rates on a present value basis compared to traditional utility financing mechanisms, and authorize the Utility to collect a NBC sufficient to pay debt service on the recovery bonds. The application also requested to exclude the securitized debt from the Utility's ratemaking capital structure and to adjust its 2020 GRC revenue requirement following the issuance of the recovery bonds. The application indicated that the issuance of the bonds is anticipated to occur before the end of 2021, but timing is subject to change.

On June 24, 2021, the CPUC issued a decision granting the Utility's application and authorizing the Utility to issue up to approximately $1.2 billion of recovery bonds. On July 6, 2021, the financing order became final and non-appealable.

2020-2022 Wildfire Mitigation Plan

As previously disclosed, on February 7, 2020, the Utility submitted its 2020 WMP and utility survey. The Utility's 2020 WMP describes the Utility's wildfire safety programs, which are focused on three key areas: reducing the potential for fires to be started by electrical equipment, reducing the potential for fires to spread, and minimizing the frequency, scope and duration of PSPS events, as well as providing historical data requested by the guidelines. The Utility's 2020 WMP covers a three-year period from 2020 to 2022 but is updated annually.

On June 11, 2020, the CPUC voted to adopt two resolutions which conditionally approved the Utility's 2020 WMP. The resolutions indicate that while the Utility's 2020 WMP met the minimum requirements for its submission, the deficiencies found, classified as severity level A, B, or C Conditions, require significant follow-up from the Utility and oversight to ensure appropriate remedies for the deficiencies. The Utility received 41 Conditions in total with the first set, classified as Class A Conditions, submitted on July 27, 2020. The second set, Class B Conditions, were completed on September 9, 2020 and the third, Class C Conditions, were submitted as part of the 2021 WMP update on February 5, 2021. On December 30, 2020, the OEIS issued a Notice of Non-Compliance finding that the Utility's responses to the Class A Conditions were insufficient. The OEIS has required the Utility to include 39 action items in its 2021 WMP to address the insufficient responses. On January 8, 2021, the OEIS issued a Notice of Non-Compliance finding that the Utility's quarterly report addressing the Class B Conditions was insufficient. The OEIS directed the Utility to respond to 84 action items in its 2021 WMP or via a supplemental filing by February 26, 2021.

The Utility's 2021 WMP was submitted on February 5, 2021. The 2021 WMP updated the 2020 WMP and addressed the Utility's wildfire safety programs focused on reducing the potential for catastrophic wildfires related to electrical equipment, reducing the potential for fires to spread and reducing the impact of PSPS events. On February 26, 2021, the Utility submitted its supplemental filing addressing the remaining action items regarding the Class A and Class B conditions that OEIS determined were insufficient.

Failure to remedy insufficiencies in the 2020-2022 WMP could lead to enforcement actions by the CPUC, including potentially placing the Utility in the EOEP, and making the Utility unable to obtain an AB 1054 safety certification and, as a result, unable to access the Wildfire Fund, which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

On April 27, 2021, the OEIS extended its deadline to issue a determination on the Utility's 2021 WMP. On May 4, 2021, the OEIS issued a revision notice requiring the Utility to address six issues. The Utility submitted its response to the revision notice on June 3, 2021, and parties filed comments on June 10, 2021 and reply comments on June 16, 2021. The Utility is unable to predict the timing or outcome of a CPUC decision on the 2021 WMP.

In 2021, the Utility notified the CPUC that it had missed some inspections and other targets subject to the 2020 WMP. The Utility is undertaking a review of its electric asset inspections. For more information, see "Electric Asset Inspections" below.

On July 1, 2021, the Utility received a copy of the Independent Evaluator's report concerning compliance with the 2020 WMP. The Independent Evaluator generally found that the work conducted by the Utility in 2020 aligned with the 2020 WMP targets but did find exceptions and areas of non-compliance. The Independent Evaluator also reviewed the Utility's funding of 2020 WMP initiatives and determined that while most initiatives were fully funded when compared to budget, there were some initiatives where the Utility underspent in comparison to budget. The Utility may submit comments on the Independent Evaluator report by August 16, 2021.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs in connection with the 2019 WMP, 2020 WMP, and 2021 WMP recorded in the FRMMA and WMPMA, which the Utility expects will be substantial.

OIR Regarding Microgrids

As previously disclosed, on September 19, 2019, the CPUC initiated a rulemaking proceeding to examine microgrid implementation issues and resiliency strategies pursuant to SB 1339. In the first track of that proceeding, the CPUC sought to deploy resiliency planning in areas that are prone to outage events and wildfires, with the stated goal of putting some microgrid and other resiliency strategies in place by spring or summer 2020, if not sooner. At the CPUC's direction, the Utility submitted a proposal for immediate implementation of resiliency strategies on January 21, 2020. The Utility's proposal contained three components for which it sought scope and cost recovery authorization of up to approximately $379 million in both expense and capital.

The CPUC adopted a decision in the first track of the proceeding on June 11, 2020, which approved with conditions the Utility's proposal and requires the Utility to track costs in a new memorandum account for subsequent regulatory review and recovery in rates.

The CPUC initiated the second track of the proceeding on July 3, 2020, which focused on the transition from diesel mobile generation to alternative, cleaner backup power generation. On January 14, 2021, the CPUC adopted a final decision in the second track of the proceeding (the "Track 2 Decision"). The Track 2 Decision requires the Utility to justify the amount of temporary generation necessary for use at substations during the 2021 wildfire season; to propose a longer-term framework for substation generation solutions to mitigate PSPS outage events by June 30, 2021; and to file an application by September 30, 2021 to recover the costs incurred in 2020 associated with the use of temporary generation to mitigate PSPS outages. The Track 2 Decision also authorizes the Utility to record the future costs of temporary generation for substations in a memorandum account and to recover the costs for any clean substation project(s) through a one-way balancing account, up to a $350 million cap and subject to other eligibility requirements.

On March 5, 2021, the Utility submitted an advice letter seeking authorization to track and record costs for the reservation and operation of up to 168 MW of temporary generation to support substation-level microgrids during 2021 PSPS events. On April 14, 2021, the CPUC approved the Utility's request to reserve up to 168 MW of temporary generation in 2021. The CPUC indicated that it would separately address the Utility's plan to establish any clean substation project(s) in 2021. On June 4, 2021, the Utility notified the CPUC that it did not identify any generation-based clean substation projects within the cost-effectiveness parameters established by the Track 2 Decision, and proposed a demand response-based clean substation pilot project.

On July 15, 2021, the CPUC adopted a decision in the third track of this proceeding that would suspend the capacity reservation component of utility standby rates for eligible microgrids that meet California Air Resource Board air pollution standards for generation. The decision requires the IOUs to establish two-way balancing accounts to track costs associated with the suspension of the capacity reservation component of the standby charge, and to also track the revenue received from a new Demand Assurance Charge mechanism, to true-up costs for future recovery from customers. According to the decision, in 2026, the CPUC will evaluate the effectiveness of the reservation capacity rate suspension and the adequacy of the Demand Assurance Charge.

On June 30, 2021, the Utility filed a new application at the CPUC regarding the selection and procurement of substation-level microgrid projects for PSPS mitigation going forward. The application also proposes a framework for seeking cost recovery of selected projects. Under the application's proposed schedule, the CPUC would issue a final CPUC decision after March 2022.

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

Regionalization Proposal

On June 30, 2020, the Utility filed its application for approval of its Regionalization Proposal with the CPUC. The Utility's proposal would divide its service area into five new regions to further improve safety and reliability, core operations, and be more responsive to the needs of its customers. The Utility's Regionalization Proposal describes the development of these regions, plans to hire new regional leadership, and a new regional organization structure. The Utility's application requested the CPUC to approve a memorandum account to record any incremental costs the Utility incurs in connection with the development and implementation of regionalization. The memorandum account proposal was approved on October 2, 2020. On June 1, 2021, the Utility announced the hiring of five regional vice presidents and five regional safety directors.

On June 29, 2021, the CPUC issued an amended scoping memo that provides the parties a right to request evidentiary hearings. If granted, hearings will occur the first week of August 2021. Opening and reply briefs are due August 16, 2021 and August 23, 2021, respectively. The case will then be submitted for a decision.

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

Wildfire Fund Non-Bypassable Charge

In response to directives in AB 1054, on July 26, 2019, the CPUC opened a new rulemaking to consider the authorization of an NBC to support the Wildfire Fund. On October 24, 2019, the CPUC issued a final decision finding that the imposition of the NBC is just and reasonable. The decision also continues the same allocation of the wildfire charge revenue requirement among the IOUs as previously adopted for the Department of Water Resources power and bond charge revenue requirements. The decision adopts revenue requirements for the Utility of $404.6 million, which is based on average annual collections and will expire at the end of the year 2035.

On December 17, 2020, the CPUC authorized the Utility to collect the Wildfire Fund NBC from eligible customers from January 1, 2021 through December 31, 2021 in the amount of $0.00580 per kilowatt-hour. On December 30, 2020, the Utility submitted an advice letter incorporating final rates effective January 1, 2021.

On March 4, 2021, the CPUC issued a final decision which created a new rulemaking regarding the amount of the Wildfire Fund NBC in 2022 and 2023. A prehearing conference for the new rulemaking took place on April 26, 2021. The Utility expects a final decision on the 2022 Wildfire Fund NBC in December 2021 and a final decision on the 2023 Wildfire Fund NBC in December 2022.

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

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

On February 26, 2021, the ALJ issued a ruling seeking comments regarding penalties and financial incentives and potential mechanisms for implementation. Other questions included whether the CPUC should establish new rules to attempt to decrease the risk of electricity price volatility caused by potential gas supply issues and if certain pipeline operating procedures should be uniform across the state. Parties filed comments on the questions on March 19, 2021. On March 30, 2021, several parties filed a joint motion to suspend the procedural schedule for Tracks 1A and 1B (Phase 1) due to inadequate time to prepare testimony if determined by the CPUC to be necessary. In accordance with the amended procedural schedule, on April 2, 2021, parties filed motions regarding the need to serve testimony, file briefs or request evidentiary hearings in Phase 1. On April 15, 2021, the ALJ issued a ruling suspending the amended procedural schedule. On June 25, 2021, the ALJ issued a ruling requesting comments on a CPUC staff proposal to impose daily financial penalties on a gas utility for failing to meet an annual backbone capacity standard for more than nine months. The Utility will file comments by July 30, 2021 and reply comments by August 15, 2021.

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

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

On May 30, 2019, the CPUC approved a decision for phase one of this proceeding, which adopted de-energization communication and notification guidelines for the electric IOUs along with updates to requirements established in Resolution ESRB-8.

On May 28, 2020, the CPUC adopted PSPS Phase 2 guidelines, which require utilities to restore energy within 24 hours after the end of a PSPS event where possible; to consult with critical facilities on back-up power for PSPS events; and to support access and functional needs populations during PSPS events, including powering medical equipment at customer resource centers.

On December 2, 2020, the Utility and other parties submitted comments in this proceeding in response to an August 3, 2020 scoping ruling regarding SED’s report in a separate PSPS-related proceeding, OII to Examine the Late 2019 Public Safety Power Shutoff Events. In their comments, the Utility and other parties commented that issues raised in SED’s report should be addressed in a Phase 3 of this OIR rulemaking proceeding.

On November 12, 2019, the assigned commissioner and ALJ issued an order to show cause directing the Utility to show why it should not be sanctioned for the PSPS events of October 9-12, 2019, October 23-25, 2019, and October 26-November 1, 2019.

Opening briefs were filed on October 30, 2020 by all parties, which included an intervenor proposing financial penalties against the Utility of $166 million. If adopted by the CPUC, such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Reply briefs were filed by all parties on November 17, 2020, including the Utility, which opposed the imposition of any penalties. On May 26, 2021, the presiding officer issued a POD finding that the Utility was not reasonable in its implementation of these PSPS events. The POD proposes a penalty of $106 million, which would be offset by $86 million in bill credits that the Utility has already provided to customers. On June 25, 2021, the Utility filed an appeal of the POD arguing that no penalty should be imposed beyond the previously issued bill credits. That same day, the California Large Energy Consumers Association also filed an appeal asking that some portion of the bill credits be distributed to industrial customers. The Utility and others filed responses to the appeals on July 12, 2021. The CPUC may approve the POD or issue a decision different.

On June 24, 2021, the CPUC adopted PSPS Phase 3 guidelines, which require utilities to submit annual pre- and post- season reports, have certain percentages of Community Resource Centers be indoors, conduct public outreach in all languages prevalent in its service territory, have a webpage that explains "critical facility" requirements, implement new notification requirements and conduct de-energization simulation exercises. The Phase 3 guidelines also clarify that the CPUC may review the reasonableness of a decision to initiate a PSPS event at any time and that IOUs must ensure customers are able to use medical equipment during PSPS events.

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

OII to Examine the Late 2019 Public Safety Power Shutoff Events

On November 13, 2019, the CPUC issued an OII to determine "whether California's IOUs prioritized safety and complied with the CPUC's regulations and requirements with respect to their PSPS events in late 2019." The first phase of this proceeding focuses on (1) the effectiveness of the utilities' procedures to notify the public of the PSPS events, (2) the utilities' communication and coordination with first responders, local jurisdictions and state agencies, and (3) the utilities' management of their resources to ensure public safety. In later phases of this proceeding, the CPUC may consider taking action if it finds violations of statutes or its decisions or GOs have been committed and to enforce compliance, if necessary.

On August 3, 2020, the assigned commissioner issued a ruling and scoping memo directing parties to file comments regarding: (1) whether the Utility and other large electric IOUs in October and November 2019 complied with the criteria set forth in applicable laws and regulations when pro-actively deenergizing and re-energizing their power lines, and (2) what corrective actions the CPUC should require of the Utility and other large electric IOUs for any failure in late 2019 to comply with the then-existing PSPS guidelines. Each of the large electric IOUs filed their comments on September 2, 2020, intervenors filed their comments on October 16, 2020, and reply comments were filed by all parties on November 16, 2020. Several parties proposed in their comments that penalties be imposed on the utilities for inadequate implementation of the PSPS events. For example, TURN proposed that the CPUC should treat each customer affected by a PSPS event, for which the utility has not adequately demonstrated that the benefits outweigh the public safety risks, as a separate offense, with each offense subject to a penalty of no less than $500 and no more than $100,000. In reply comments, the Utility argued that the proposed penalties should not be adopted for procedural and substantive reasons.

On March 10, 2021, the presiding judge directed the Utility and the other large electric IOUs to provide an accounting of the PSPS events that occurred in their service territories in calendar years 2019 and 2020 and how those PSPS events impacted revenue collections. On April 7, 2021, the Utility and San Diego Gas & Electric submitted their accountings. The Utility estimated the revenue impact from the 2019 PSPS and 2020 PSPS events at approximately $14 million and $5 million, respectively.

On April 20, 2021, the CPUC issued a PD in the case that found each of the large electric IOUs to be noncompliant with CPUC-required guidelines in certain of their 2019 PSPS events. The PD proposed a financial remedy and a number of corrective actions. The financial remedy would consist of forgoing collection of revenues from customers associated with electricity not sold during future PSPS events until it can be demonstrated that the utilities have made improvements in assessing public harm when determining whether to initiate a PSPS event. The corrective actions involve the Utility's processes, reporting, and other aspects of its PSPS program. The CPUC's final decision was issued on June 7, 2021 and modified some of the PD's corrective actions but retained the financial remedy. On July 7, 2021, the Acton Town Council filed an application to rehear the decision. Responses to the application for rehearing were filed on July 22, 2021. The Utility is unable to predict the outcome of this proceeding.

Power Charge Indifference Adjustment OIR

As previously disclosed, in 2017, the CPUC initiated the PCIA Rulemaking to make refinements to the PCIA, a cost recovery mechanism to ensure that customers that leave the Utility's bundled service for a non-Utility provider, such as a direct access or CCA provider, pay their fair share of the above-market costs associated with long-term power purchase commitments and Utility-owned generation made on their behalf. The above-market costs of the Utility's generation portfolio are calculated using benchmarks for energy, RA and renewables portfolio standard attributes.

As previously disclosed, on October 11, 2018, the CPUC approved a phase one decision to modify the PCIA methodology. The Utility implemented a revised PCIA reflecting this decision in rates as of July 1, 2019.

Also, as previously disclosed, on October 10, 2019, the CPUC approved a final decision that finalized the true-up for the new PCIA methodology.

On March 26, 2020, the CPUC approved a final decision on departing load forecasting and PCIA bill presentation issues, establishing that the IOUs shall show a PCIA line item in their tariffs and bill summary tables on all customer bills, which shall be implemented by the last business day of 2021.

On August 6, 2020, the CPUC issued a final decision that would provide a non-Utility provider an option to prepay its entire PCIA obligation.

On May 20, 2021 the CPUC approved a final decision, removing the PCIA rate cap and trigger mechanism and adopting a limited proposal for portfolio management focused only on the Utility's renewables portfolio standard eligible resources. On June 23, 2021, six parties filed a joint application for rehearing. On July 8, 2021, the Utility filed reply comments.

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

Central Procurement of the Resource Adequacy Program

On June 17, 2020, the CPUC issued a decision on the Central Procurement of the RA program. The decision shifts local RA procurement responsibility under the CPUC's RA program from all LSEs to a CPE in two distribution service areas, including the Utility's distribution service area, resulting in a change from decentralized to centralized local RA procurement in those distribution service areas. The decision also adopted implementation details for the central procurement of multi-year local RA, ordered the Utility and another IOU to serve as the CPE for their respective distribution service areas, and adopted a hybrid central procurement framework for the multi-year local RA program beginning for the 2023 RA compliance year.

The decision requires the Utility, as the CPE for its distribution service area, to conduct a competitive, all-source solicitation for local RA procurement, with any existing local resource that does not have a contract, any new local resource that can be brought online in time to meet solicitation requirements, or any LSE or third-party with an existing local RA contract eligible to bid into the solicitation.

On December 3, 2020, the CPUC issued a follow-up decision adopting a compensation mechanism applicable to certain local resources that may be procured by the CPE for purposes of reducing the total CPE procurement requirements. This mechanism applies to new preferred local resources and new local energy storage resources, including utility-owned generation. Procurement by the Utility of, and compensation for, such resources will occur outside of the competitive, all-source solicitation.

The cost allocation mechanism methodology is adopted as the cost recovery mechanism to cover procurement costs incurred in serving the central procurement function. The administrative costs incurred in serving the central procurement entity function will also be recoverable under the cost allocation mechanism.

On January 29, 2021, the Utility submitted an advice letter seeking approval by the CPUC's energy division of a detailed CPE procurement plan. On March 25, 2021, the CPUC's energy division issued a disposition letter converting the advice letter into an information-only submittal, which does not require approval by the CPUC.

On April 23, 2021, the Utility issued the 2021 CPE local RA request for offers in furtherance of fulfilling its obligations as CPE under the above-referenced CPUC decisions. Execution of any agreements resulting from the request for offers is estimated to occur in August or early September 2021.

Integrated Resource Planning Procurement

On November 13, 2019, the CPUC issued a decision that takes a number of steps to address the potential for system RA shortages beginning in 2021. The decision requires incremental procurement of system-level qualifying RA capacity of 3,300 MWs by all LSEs operating within the CAISO's balancing area for the period 2021-2023, of which the Utility is responsible for 716.9 MWs for its bundled customer portion. The decision requires that at least 50% of LSE resource responsibilities come online by August 1, 2021, at least 75% by August 1, 2022, and the remaining by August 1, 2023. Additionally, the decision directs the IOUs to act as the backstop procurement agent for CCAs and Energy Service Providers (ESPs) that choose not to voluntarily self-procure or that fail to meet their procurement responsibilities after electing to self-provide their assigned MWs of system RA capacity under the decision. On April 15, 2020, the ALJ issued a ruling that the Utility must procure 48.2 MWs of RA capacity for LSEs that chose to opt-out of voluntarily self-providing their required portion.

The Utility has procured its required RA capacity for the August 1, 2021 milestone from third parties through CPUC-approved contracts for lithium-ion battery energy storage resources with terms ranging from 10-15 years. On December 22, 2020, the Utility filed an advice letter seeking CPUC approval of an additional group of similar contracts that would satisfy the balance of the Utility's procurement obligations for the August 1, 2022 and August 1, 2023 milestones. On April 15, 2021, the CPUC approved the contracts.

The CPUC is developing a modified cost allocation mechanism methodology, under which the Utility will be able to recover procurement and administrative costs it incurs in serving the backstop procurement function.

On June 24, 2021, the CPUC unanimously adopted a decision to address incremental system reliability needs between 2024 and 2026 due to, in part, the pending retirements of Diablo Canyon and once-through-cooling natural gas plants in Southern California by requiring at least 11,500 MW of additional net qualifying capacity to be procured by LSEs subject to the CPUC's integrated resource planning authority. The decision sets annual procurement requirements of 2,000 MW by 2023, an additional 6,000 MW by 2024, an additional 1,500 MW by 2025, and an additional 2,000 MW by 2026. The decision sets the Utility's share of the procurement at 2,302 MW of incremental net qualifying capacity.

OIR to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities

On July 20, 2020, the CPUC initiated a rulemaking proceeding to consider ways to strengthen the risk-based decision-making framework that regulated energy utilities use to assess, manage, mitigate and minimize safety risks. The rulemaking will build on requirements for a utility risk framework adopted in the first Safety Model Assessment Proceeding. The CPUC's goal is to further the prioritization of safety by electric and gas utilities.

On November 2, 2020, the assigned commissioner issued a scoping memo establishing the scope, schedule, and categorization for Phase I and Phase II of the proceeding. Phase I, which began November 2020, is considering (i) clarifications to the technical requirements of the risk-based decision-making framework; (ii) safety and operational performance metrics; and (iii) refining RAMP procedural requirements.

On November 17, 2020, the assigned commissioner issued a ruling regarding the development of safety and operational metrics for the Utility. The ruling directed the Utility to propose metrics that are "suitable for the use as triggering events as specified in the Enhanced Oversight and Enforcement Process" and "suitable, over time, for the Commission, intervenors, and the public to potentially use to gauge the safety and operational performance of all gas and electric IOUs." On January 15, 2021, the Utility filed a response proposing 12 safety and operational metrics using the criteria outlined by the ruling. On January 25, 2021, parties filed responses to the Utility's proposal. On January 28, 2021, the CPUC hosted a public workshop where the Utility, the other IOUs, and intervenors commented on the Utility's safety and operational metrics proposal. All parties filed comments on the Utility's safety and operational metrics on March 1, 2021.

On June 4, 2021, the ALJ issued a ruling incorporating a staff proposal regarding the Utility's safety and operational metrics. The proposal recommends 40 safety and operational metrics addressing worker and contractor safety, electric safety risks, reliability, gas safety risks, customer satisfaction, and clean energy goals. Parties filed opening and reply comments seeking modifications to the proposal on June 29 and July 9, 2021, respectively. A PD is expected in August 2021.

OIR to Revisit Net Energy Metering Tariffs

On August 17, 2020, the CPUC initiated a rulemaking proceeding to develop a successor to the existing NEM tariffs. The successor tariff is being developed pursuant to the requirements of AB 327. Under AB 327, the successor to the existing NEM tariffs should provide customer-generators with credit or compensation for electricity generated by their renewable facilities based on the value of that generation to all customers and allows customer-sited renewable generation to grow sustainably among different types of customers.

On November 19, 2020, the assigned commissioner and the ALJ issued a scoping memo and ruling for this proceeding. The scoping memo separated the proceeding into two phases. In the first phase, the CPUC will address several issues, including determining the principles to assist in the development and evaluation of a successor to the current NEM tariffs, assessing what information from a study on existing tariffs should inform the successor, outlining the methods to use to analyze the program elements and the resulting proposals, and determining the program elements or specific features that should be included in the successor tariff. In the second phase, the CPUC will consider what additional or enhanced consumer protections for customers should be adopted, as well as other issues that may arise, such as the virtual net energy metering tariffs, NEM aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the NEM fuel cell tariff.

On February 11, 2021, the CPUC issued a final decision that outlined certain guiding principles to assist in the development and evaluation of proposals for successor to the current NEM tariff.

Parties submitted opening testimony on June 18, 2021 and rebuttal testimony on July 16, 2021. Evidentiary hearings commenced on July 26, 2021, with briefing expected to be complete in September 2021. A PD is expected in the fourth quarter of 2021.

OIR to Address Energy Utility Customer Debt Accumulated during the Coronavirus Pandemic

On February 11, 2021, the CPUC initiated a rulemaking proceeding to consider arrearage relief for utility customers who will have outstanding utility bills when the moratorium on service disconnections ends. The OIR will evaluate a more global program beyond the currently approved arrearage management program focused on low-income residential customers that is funded by the Utility's customers. The OIR may consider various funding approaches for this expanded debt forgiveness proposal, which could include shareholder funding.

On June 30, 2021, the CPUC issued a final decision directing the Utility and other IOUs to automatically enroll residential customers and small business customers more than 60 days in arrears in payment plans. The decision also sets forth an intent to revisit additional remaining issues initially scoped in the proceeding, including incorporation of state and federally funded arrearage relief. The decision also extends the moratorium on service disconnections for residential and small business, as well as medium and large commercial and industrial customers through September 30, 2021.

Electric Asset Inspections

The Utility has notified the CPUC of various errors relating to inspections and maintenance of its electric assets or implementation of WMP initiatives. These notices include missed inspections or the inability to locate records evidencing performance of inspections required under CPUC GOs 95 and 165 (including failure to perform inspections in compliance with GO 165 of approximately 55,000 poles in 2020) and errors regarding reporting meeting targets set by the Utility's 2020 WMP. In these notices, the Utility describes the failures and corrective actions the Utility is taking to remediate these issues and to prevent recurrence in the future. Among other corrective measures, the Utility has developed short-term and longer-term systemic corrective actions to address these errors, including performing enhanced inspections for poles with outdated or incomplete GO 165 inspection records and strengthening the Utility's asset registry, as well as corrective actions regarding reporting on the progress toward WMP targets.

The Utility continues to evaluate whether there are additional failures to comply with GOs 95 and 165 and the 2020 WMP, beyond those identified in submitted self-reports. The Utility intends to update the CPUC upon completion of its reviews. The Utility could face penalties, enforcement action, or other adverse legal or regulatory consequences for these errors or omissions, including under the EOEP. The Utility is unable to predict the likelihood and the amounts of potential fines or penalties, if any, related to these matters.

Rate Cases

2020 Cost of Capital Proceeding

On December 19, 2019, the CPUC approved a final decision in the 2020 Cost of Capital proceeding, maintaining the Utility's return on common equity at the 2019 level of 10.25% for the three-year period beginning January 1, 2020. The decision maintains the common equity component of the Utility's capital structure at 52%, and reduces its preferred stock component from 1% to 0.5%. The decision also approves the cost of debt requested by the Utility. The Utility's annual cost of capital adjustment mechanism, which allows for changes in the Utility's authorized ROE and cost of debt, also remains unchanged. In any year in which the difference between the average Moody's utility bond rates, as measured in the 12-month period from October through September (the index), and 4.5% (the benchmark) exceeds 100 basis points, the Utility's ROE will be adjusted by one-half of such difference, and the cost of debt will be trued up to the most recent recorded cost of debt. The Utility must initiate this adjustment mechanism by filing an advice letter on or before October 15, to become effective on January 1 of the next year. The mechanism did not trigger in September 2020; however, as of July 27, 2021, the index was more than 100 basis points below the 4.5% benchmark. If the mechanism triggers in October 2021, then for 2022 the ROE and the cost of debt will be adjusted accordingly.

2015 Gas Transmission and Storage Rate Case

As previously disclosed, in its final decision 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 forecast to be 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 audit report was released June 2, 2020 and did not recommend any additional disallowances. The 2015 GT&S decision authorized the Utility to seek recovery, through a separate application, of those costs not recommended for disallowance by the audit. On July 31, 2020, the Utility filed an application seeking recovery of $416.3 million in 2015 to 2022 revenue associated with $512 million of recorded capital expenditures. On October 16, 2020, the assigned commissioner issued a scoping memo establishing the scope and schedule for the proceeding. On July 7, 2021, a joint motion was filed to adopt a settlement agreement. If approved by the CPUC, the settlement agreement would resolve all issues in this proceeding and would authorize a $356.3 million revenue requirement for the period of 2015 through 2022. Of this amount, $313.3 million of revenues for the period 2015 through 2021 would be amortized in rates over 60 months and $43 million associated with 2022 would be amortized in rates over 12 months through an annual gas true up filing for rates effective January 1, 2022. Going forward, the as-yet undepreciated capital plant associated with this application would be included in test year 2023 rate base in the Utility's consolidated 2023 GRC. On July 9, 2021, the ALJ granted a motion to include an additional party. The ALJ ruled that the party's participation would be limited to commenting on the settlement agreement and proposed decision, and that the party may not broaden the current scope of issues or introduce new evidentiary information.

On November 10, 2020, the Utility filed a motion seeking approximately $100 million in interim rates, assuming the CPUC reaches a final decision in this matter in late 2021 or early 2022. The CPUC has not yet ruled upon the Utility's motion.

Transmission Owner Rate Cases

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

As previously disclosed, on January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of the 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. If the FERC concluded 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. Those rate case decisions were remanded to the FERC for further proceedings consistent with the Court of Appeals' opinion.

On July 18, 2019, the FERC issued its order on remand reaffirming its prior grant of the Utility's request for the 50-basis point ROE adder.

On March 17, 2020, the FERC issued an order denying requests for rehearing previously filed by several parties. On May 11, 2020, the CPUC and a number of other parties filed a petition for review of the FERC's orders in the Ninth Circuit Court of Appeals. Oral argument was held on April 16, 2021. The Utility is unable to predict the timing and outcome of this proceeding.

For more information, see the 2020 Form 10-K.

Transmission Owner Rate Case for 2017

As previously disclosed, on July 29, 2016, the Utility filed its TO18 rate case with the FERC requesting a 2017 retail electric transmission revenue requirement of $1.72 billion, a $387 million increase over the 2016 revenue requirement of $1.33 billion. The forecasted network transmission rate base for 2017 was $6.7 billion. The Utility sought a ROE of 10.9%, which included an incentive component of 50 basis points for the Utility's continuing participation in the CAISO.

Also, as previously disclosed, on October 1, 2018, the ALJ issued an initial decision in the TO18 rate case proposing a ROE of 9.13% compared to the Utility's request of 10.9%, and an estimated composite depreciation rate of 2.94% compared to the Utility's request of 3.25%. In addition, the ALJ proposed to reduce forecasted capital and expense spending to actual costs incurred for the rate case period, proposed to remove certain items from the Utility's rate base and revenue requirement, and rejected the Utility's direct assignment of common plant to transmission and required the allocation of all common plant between CPUC and FERC jurisdiction be based on operating and maintenance labor ratios.

As previously disclosed, on October 15, 2020, the FERC issued an order that affirmed in part and reversed in part the initial decision. The order, among other things, rejected the Utility's direct assignment of common plant to FERC and required the allocation of all common plant between CPUC and FERC jurisdiction be based on operating and maintenance labor ratios. The order reopened the record for the limited purpose of allowing the participants to the proceeding an opportunity to present written evidence concerning the FERC's revised ROE methodology adopted in the FERC Opinion No. 569-A, issued on May 21, 2020. Initial briefs and testimony were filed on December 14, 2020 and responses were filed on February 12, 2021.

As previously disclosed, on December 17, 2020, the FERC denied all the pending requests for rehearing that were previously submitted by the Utility and intervenors. On February 11, 2021, the Utility filed a petition for review of the order in the Court of Appeals. On March 4, 2021, the Court of Appeals issued an order holding the Utility's petition for review in abeyance until July 14, 2021 so that the FERC has time to issue a substantive order on rehearing. On April 15, 2021, the FERC issued a substantive order denying the Utility's request for rehearing and granting the request for rehearing of two parties regarding the impact of the Tax Act on TO18 rates in January and February 2018. The Utility has sought rehearing of the FERC's reversal on the applicability of the Tax Act on TO18 rates which may affect the timing for judicial review of the FERC order on the Utility's request for rehearing. On June 8, 2021, the Utility filed a second petition for review in the Court of Appeals on aspects of the rehearing order other than the Tax Act. On June 17, 2021, the FERC issued a notice denying the Utility's request for rehearing on the applicability of the Tax Act on TO18 rates by operation of law and providing for further consideration. On June 21, 2021, the Court of Appeals ordered that the Utility's two petitions for review be consolidated and held both petitions in abeyance until July 14, 2021. On July 22, 2021, the Court of Appeals ordered that the Utility's two petitions for review be held in abeyance until further order of the court and directed the parties to file motions to govern further proceedings within 75 days after the FERC issues a substantive order on the Utility's request for rehearing on the applicability of the Tax Act on TO18 rates.

As a result of the FERC's April 15, 2021 order denying rehearing on the common plant allocation, the Utility increased its Regulatory liabilities for amounts previously collected during the TO18, TO19, and TO20 rate case periods from 2017 through the second quarter of 2021 by approximately $274 million. A portion of these common plant costs are expected to be recovered at the CPUC in a separate application and as a result, as of June 30, 2021, the Utility has recorded approximately $168 million to Regulatory assets.

Aside from the ultimate outcome of the common plant allocation, which is subject to further appellate briefing and a further FERC decision on ROE, the FERC's April 15, 2021 order is not expected to result in a material impact on the Utility's financial condition, results of operations, liquidity, and cash flows. Some of the issues that will be decided in a final and unappealable TO18 decision, including the common plant allocation, will also be incorporated into the Utility's TO19 and TO20 rate cases. (See "Transmission Owner Rate Case Revenue Subject to Refund" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

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

For more information, see the 2020 Form 10-K.

LEGISLATIVE AND REGULATORY INITIATIVES

Assembly Bill 1054

On July 12, 2019, the California governor signed into law AB 1054, a bill which provides for the establishment of a statewide fund that will be available for eligible electric utility companies to pay eligible claims for liabilities arising from wildfires occurring after July 12, 2019 that are caused by the applicable electric utility company's equipment, subject to the terms and conditions of AB 1054. Eligible claims are claims for third party damages resulting from any such wildfires, limited to the portion of such claims that exceeds the greater of (i) $1.0 billion in the aggregate in any year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to section 3293 of the Public Utilities Code, added by AB 1054.

AB 1054 also provides that the first $5.0 billion expended in the aggregate by California's three large electric IOUs on fire risk mitigation capital expenditures included in their respective approved WMPs will be excluded from their respective equity rate bases. The $5.0 billion of capital expenditures will be allocated among the large electric IOUs in accordance with their Wildfire Fund allocation metrics. (See Note 3 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) AB 1054 contemplates that such capital expenditures may be securitized through a customer charge. On February 24, 2021, the Utility filed an application with the CPUC seeking authorization for a transaction to securitize up to a principal amount of approximately $1.19 billion related to fire risk mitigation capital expenditures that have been or will be incurred by the Utility in 2020 and 2021. The CPUC issued a financing order authorizing the transaction on June 24, 2021.

Each of California's large electric IOUs has elected to participate in the Wildfire Fund. On July 1, 2020, having satisfied the conditions for the Utility's participation in the Wildfire Fund, the Utility deposited approximately $5 billion in the Wildfire Fund, which represents the Utility's initial and first annual contributions. On December 30, 2020, the Utility made its second annual contribution of $193 million to the Wildfire Fund.

Assembly Bill 135

On July 16, 2021 the California governor signed into law AB 135, a bill which implements a $1.0 billion appropriation to prevent service disconnections for utility customers experiencing financial hardship due to the COVID-19 pandemic by providing financing assistance to customer accounts in arrears. AB 135 sets aside $695 million for IOU electric and gas distribution customers. The Utility will receive a portion of the funding set aside for IOU electric and gas customers to reduce the amounts owed by customer accounts in arrears. The amount of funding will be determined by the California Department of Community Services and Development, which is the agency responsible for administering the California Arrearage Payment Program.

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 greenhouse gas 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 11 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 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 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 11 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 2020 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 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2020 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 2020 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the six months ended June 30, 2021.

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, contributions to the Wildfire Fund, and pension and other post-retirement benefit 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 and assumptions. These accounting policies and their key characteristics are discussed in detail in the 2020 Form 10-K.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 3 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

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 Notes 8 and 9 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 June 30, 2021, 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 Exchange Act, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended June 30, 2021, 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

PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see Notes 2, 10, and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part I, MD&A: "Enforcement and Litigation Matters."

Each of PG&E Corporation and the Utility have elected to disclose environmental proceedings described in Item 103(c)(3)(iii) of Regulation S- K unless it reasonably believes that such proceeding will result in no monetary sanctions, or in monetary sanctions, exclusive of interest and costs, of less than $1 million.

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 2020 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Forward-Looking Statements."

Because, on July 8, 2021, PG&E Corporation and the Utility agreed to treat the Fire Victim Trust as a "grantor trust," the application of the Ownership Restrictions, as defined in PG&E Corporation's Amended Articles of Incorporation, will be determined on the basis of a number of shares outstanding that could differ materially from the number of shares reported as outstanding on the cover page of its periodic reports under the Exchange Act.

The Plan contemplated that the Fire Victim Trust would be treated as a "qualified settlement fund" for U.S. federal and state income tax purposes, subject to PG&E Corporation's ability to elect to treat the Fire Victim Trust as a "grantor trust" for U.S. federal and state income tax purposes instead. In January 2021, PG&E Corporation received an IRS ruling that states the Utility is eligible to make a grantor trust election for U.S. federal income tax purposes, with respect to the Fire Victim Trust and addressed certain, but not all, related issues. PG&E Corporation believed certain benefits associated with "grantor trust" treatment, including a potentially larger tax deduction related to the proceeds realized by the Fire Victim Trust from the sale of shares transferred to the Fire Victim Trust, could be realized, but only if PG&E Corporation and the Fire Victim Trust could meet certain requirements of the Internal Revenue Code and Treasury Regulations thereunder, relating to sales of PG&E Corporation common stock. On April 29, 2021, the Bankruptcy Court entered an order approving the material terms of the PG&E Fire Victim Trust Share Exchange Agreement between PG&E Corporation, the Utility and the Fire Victim Trust that supports the election of the grantor trust treatment. On July 8, 2021, PG&E Corporation, the Utility, ShareCo and the Fire Victim Trust entered into the PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement whereby PG&E Corporation and the Utility agreed to make a "grantor trust" election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

Because PG&E Corporation and the Utility have agreed to treat the Fire Victim Trust as a "grantor trust" for U.S. federal income tax purposes, as of July 8, 2021 (which treatment will be retroactive to the inception of the Fire Victim Trust), with the election, any shares owned by the Fire Victim Trust are effectively excluded from the total number of outstanding equity securities when calculating a person's Percentage Ownership (as defined in the Amended Articles) for purposes of the Ownership Restrictions. Shares owned by ShareCo are also effectively excluded because it is a disregarded entity for tax purposes. For example, whereas the number of outstanding shares of PG&E Corporation common stock for corporate purposes as of July 26, 2021 was 2,463,016,638 shares, for purposes of the Ownership Restrictions, the number of outstanding shares of PG&E Corporation common stock would be 1,507,529,458 shares (the number of outstanding shares of common stock less the number of shares owned by the Fire Victim Trust and ShareCo as of July 26, 2021). As such, based on the total number of outstanding equity securities and assuming the Fire Victim Trust has not sold any shares of PG&E Corporation common stock, a person's effective percentage ownership restriction for purposes of the Amended Articles would have been 2.9% as of July 26, 2021. PG&E Corporation does not control the number of shares held by the Fire Victim Trust and is not able to determine in advance the number of shares the Fire Victim Trust will hold. PG&E Corporation intends to periodically make available to investors information about the number of shares of common stock held by the Fire Victim Trust as of a specified date for purposes of the Ownership Restrictions, including in its Quarterly Reports and Annual Reports filed with the SEC.

PG&E Corporation intends to enforce the Ownership Restrictions as described in the foregoing paragraph (excluding any shares owned by the Fire Victim Trust from the number of outstanding equity securities), including with respect to Transfers (as defined in the Amended Articles) occurring before July 8, 2021. However, it is anticipated that the Board of Directors of PG&E Corporation will exempt Transfers to shareholders that occurred prior to July 30, 2020 (the date PG&E Corporation initially announced it was considering treating the Fire Victim Trust as a grantor trust in its Form 10-Q for the quarterly period ended June 30, 2020), solely to the extent that such Transfers would have complied with the Ownership Restrictions if the Ownership Restrictions were applied on the basis that the shares owned by the Fire Victim Trust were treated as outstanding equity securities. For the avoidance of doubt, all other Transfers of equity securities (including acquisitions from and after July 30, 2020 by shareholders benefiting from an exemption described in the preceding sentence) will continue to be subject to the ownership restrictions. All current and prospective shareholders are advised to consider the foregoing in determining their ownership and acquisition of PG&E Corporation common stock.

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

Extreme weather, 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 and extreme heat 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 particular, the risk posed by wildfires, including during the 2021 wildfire season, has increased in the Utility's service area as a result of an ongoing extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases due to rising temperatures and 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. According to CalFire, as of December 12, 2020, over 9,639 fires have burned 4,359,517 acres, more than four percent of the state's roughly 100 million acres of land, making 2020 the largest wildfire season recorded in California's modern history. In January 2018, the CPUC approved a statewide fire-threat map that shows that approximately half of the Utility's service territory is facing "elevated" or "extreme" fire danger. Approximately 25,000 circuit miles of the Utility's nearly 81,000 distribution overhead circuit miles and approximately 5,500 miles of the nearly 18,000 transmission overhead circuit miles are in such high-fire threat areas, significantly more in total than other California IOUs.

Drought imposes other risks as well. More than 85% of California is in an extreme or exceptional drought, including 93.6% of PG&E Corporation's and the Utility's service area. Severe and prolonged drought conditions can restrict or prevent the operation of hydroelectric and natural gas generation facilities, which exacerbates resource adequacy challenges by reducing the amount of available power. Because hydroelectric generation can often be replaced only with natural gas, drought also impacts the Utility's ability to meet its renewable energy goals.

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

Further, the Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on its assets, operations, and services, as part of its Climate Vulnerability Assessment. Following completion of this assessment, the Utility is developing adaptation plans to set forth a strategy for 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, climate hazards such as heatwaves, wind storms, and flooding caused by rising sea levels and extreme storms 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.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or future wildfires.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or future wildfires.

Based on the facts and circumstances available as of the date of this report, PG&E Corporation and the Utility have determined that it is probable they will incur a loss in connection with the 2019 Kincade fire and the 2020 Zogg fire and probable that they will incur a loss in connection with the 2021 Dixie fire. Although PG&E Corporation and the Utility have recorded liabilities for probable losses in connection with the 2019 Kincade fire and the 2020 Zogg fire, these liability estimates correspond to the lower end of the range of reasonably estimable losses, do not include several categories of potential damages that are not reasonably estimable, and are subject to change based on new information. However, due to the limited amount of time that has elapsed since the start of the 2021 Dixie fire, the preliminary stages of the investigations, and the uncertainty as to the extent and magnitude of such possible losses, PG&E Corporation and the Utility cannot reasonably estimate the amount or range of such possible losses at this time.

Although there are a number of unknown facts surrounding Cal Fire's causation determinations of the 2019 Kincade fire and the 2020 Zogg fire and their ongoing investigations of the 2021 Dixie fire, the Utility could be subject to significant liability in excess of insurance coverage or amounts available under the Wildfire Fund under AB 1054 that would be expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. PG&E Corporation and the Utility have also received and have responded or are responding to data requests from the CPUC's SED relating to the 2019 Kincade fire and the 2020 Zogg fire and document and information requests from Cal Fire and the Butte County District Attorney's Office relating to the 2021 Dixie fire. Furthermore, the Sonoma County District Attorney's Office has filed criminal charges against the Utility in connection with the 2019 Kincade fire. If the Utility were to be convicted of the charges in the criminal complaint, the Utility could be subject to fines, penalties, and restitution to victims for their economic losses, as well as non-monetary remedies such as oversight requirements. The Utility does not expect that any of its liability insurance would be available to cover restitution payments ordered by the court presiding over the criminal proceeding. Additionally, the Shasta County District Attorney's Office is conducting an investigation into the 2020 Zogg fire and the Butte County and Plumas County District Attorneys' Offices are conducting investigations into the 2021 Dixie fire. PG&E Corporation and the Utility could be the subject of additional investigations, lawsuits, or enforcement actions in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or future wildfires.

Although the Utility has taken extensive measures to reduce the threat of future wildfires, the potential that the Utility's equipment will be involved in the ignition of future wildfires, including catastrophic wildfires, is significant. This risk may be attributable to, and exacerbated by, a variety of factors, including climate (in particular extended periods of seasonal dryness coupled with periods of high wind velocities and other storms), infrastructure, and vegetation conditions. Despite significant investment in mitigation measures to improve infrastructure and manage vegetation, as well as implementation of de-energization strategies, the Utility may not be successful in mitigating the risk of future wildfires.

In addition, the 2019 Kincade fire and the 2020 Zogg fire have had and, along with the 2021 Dixie fire and any future wildfires could continue to have adverse consequences on the Utility's probation proceeding, the Utility's proceedings with the CPUC and the FERC (including the Safety Culture OII), and future regulatory proceedings, including future applications for the safety certification required by AB 1054. PG&E Corporation and the Utility may also suffer additional reputational harm and face an even more challenging operating, political, and regulatory environment as a result of the 2019 Kincade fire, 2020 Zogg fire, 2021 Dixie fire or any future wildfires. For more information about the 2019 Kincade fire, the 2020 Zogg fire and 2021 Dixie fire, see Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

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

During the quarter ended June 30, 2021, PG&E Corporation did not contribute any equity securities to the Utility. Also during the quarter ended June 30, 2021, PG&E Corporation did not make any sales of unregistered equity securities in reliance on an exemption from registration under the Securities Act.

Issuer Purchases of Equity Securities

During the quarter ended June 30, 2021, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. During the quarter ended June 30, 2021, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. EXHIBITS

EXHIBIT INDEX

3.1	Amended and Restated Articles of Incorporation of PG&E Corporation, effective as of May 29, 2002, as amended by the Amendment dated June 22, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated June 20, 2020 (File No. 1-12609), Exhibit 3.1)
3.2	Bylaws of PG&E Corporation, Amended and Restated as of June 22, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated June 20, 2020 (File No. 1-12609), Exhibit 3.3)
3.3	Amended and Restated Articles of Incorporation of Pacific Gas and Electric Company, effective as of June 22, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 20, 2020 (File No. 1-2348), Exhibit 3.2)
3.4	Bylaws of Pacific Gas and Electric Company, Amended and Restated as of May 20, 2021 (incorporated by reference in Form 8-K dated May 20, 2021 (File No. 1-2348), Exhibit 3.1)
4.1	Ninth Supplemental Indenture, dated as of June 3, 2021, relating to the Mortgage Bonds, between Pacific Gas and Electric Company and the Trustee (including the form of Mortgage Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 1-2348), Exhibit 4.1)
4.2	Tenth Supplemental Indenture, dated as of June 22, 2021, relating to the collateral bonds, between Pacific Gas and Electric Company and the Trustee (including the forms of collateral bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2021 (File No. 1-2348), Exhibit 4.1)
4.3	Amended and Restated Registration Rights Agreement, dated as of July 8, 2021, by and between PG&E Corporation and the PG&E Fire Victim Trust (incorporated by reference to PG&E Corporation's Form 8-K dated July 8, 2021 (File No. 1-12609), Exhibit 4.1)
10.1	Underwriting Agreement, dated June 1, 2021, by and among Pacific Gas and Electric Company, Barclays Capital Inc., BofA Securities, Inc., Goldman Sachs & Co. LLC and J.P. Morgan Securities LLC (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 1-2348), Exhibit 1.1)
10.2	Equity Distribution Agreement, dated April 30, 2021, by and among PG&E Corporation, Barclays Capital Inc., BofA Securities, Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC, as the sales agents and forward sellers, and Barclays Bank PLC, Bank of America, N.A., Credit Suisse Capital LLC and Wells Fargo Bank, National Association, as the forward purchasers (incorporated by reference to PG&E Corporation's Form 8-K dated April 30, 2021 (File No. 1-12609), Exhibit 1.1)
10.3	Purchase Agreement, by and between Pacific Gas and Electric Company and Hines Atlas US LP, dated May 21. 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 21, 2021 (File No. 1-2348), Exhibit 10.1)

10.4		Amendment No. 1 to Credit Agreement dated as of June 22, 2021, among PG&E Corporation, the several banks and other financial institutions or entities party thereto from time to time, JP Morgan Chase Bank, N.A., as Administrative Agent and Collateral Agent (incorporated by reference to PG&E Corporation's Form 8-K dated June 22, 2021 (File No. 1-12609), Exhibit 10.1)
10.5		Amendment No. 1 to Credit Agreement dated as of June 22, 2021, among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time, JP Morgan Chase Bank, N.A., as co-Administrative Agents and Citibank, N.A,, as Designated Agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2021 (File No. 1-2348), Exhibit 10.2)
10.6		PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement, dated as of July 8, 2021, by and among PG&E Corporation, Pacific Gas and Electric Company, PG&E ShareCo LLC and the PG&E Fire Victim Trust Corporation (incorporated by reference to PG&E Corporation's Form 8-K dated July 8, 2021 (File No. 1-12609), Exhibit 10.1)
10.7	*	PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to Appendix A to PG&E Corporation's definitive proxy statement on Schedule 14A filed on April 8, 2021)
10.8	*	Form of Restricted Stock Unit Agreement for 2021 grants to Non-Employee Directors under the PG&E Corporation 2014 Long-Term Incentive Plan
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 - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SC		XBRL Taxonomy Extension Schema Document
101.CA		XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB		XBRL Taxonomy Extension Labels Linkbase Document
101.PRE		XBRL Taxonomy Extension Presentation Linkbase Document
101.DE		XBRL Taxonomy Extension Definition Linkbase Document
104		Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL 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

Dated: July 29, 2021

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster
Executive 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)