10-K Filing Data

Section: Item1

>ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in Northern and Central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility's service area is shown in the graphic below.

PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found below in Item 8. Financial Statements and Supplementary Data.

The principal executive offices of PG&E Corporation and the Utility are located at 300 Lakeside Drive, Oakland, California 94612. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. Each of PG&E Corporation and the Utility is a separate entity, with distinct creditors and claimants, and is subject to separate laws, rules, and regulations.

Over the past several years, Northern California has experienced major wildfires. For more information about material wildfires, see Item 7. MD&A, and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

This 2022 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors and "Forward-Looking Statements" above.

Triple Bottom Line

PG&E Corporation's and the Utility's purpose is to deliver for their hometowns, serve the planet, and lead with love. In support of this purpose, the companies employ a Lean operating model designed to drive more effective and responsive decision-making, reduce the difficulties many coworkers face in their day-to-day work, and deliver better outcomes for customers and communities.

PG&E Corporation and the Utility measure their progress toward the purpose by considering their impact on the "triple bottom line" of people, planet, and prosperity, which is underpinned by performance; this consideration takes into account not only the economic value they create for customers and investors, but also their responsibility to social and environmental goals. The triple bottom line is designed to balance the interests of the companies' many stakeholders, and it reflects the broader societal impacts of the companies' activities.

PG&E Corporation and the Utility will continue to consider the impact on the triple bottom line of people, planet, and prosperity in their daily operations as well as in their long-term strategic decisions. The Utility will continue to seek fair and timely regulatory treatment in order to support its customer-driven investment plan while pursuing cost-control measures that would allow it to maintain the affordability of its service. The Lean operating system is an important means of realizing PG&E Corporation's and the Utility's objective of achieving world class performance while delivering hometown service.

People

The people element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to their workforce, their customers, the residents of local communities in which the companies do business, and other stakeholders.

PG&E Corporation's and the Utility's goal is to continually reduce risk to keep customers, the communities they serve, and their workforce (both employees and contractors) safe. Their focus is on continuously building an organization where every work activity is designed to facilitate safe performance, every worker knows and practices safe behaviors, and every individual is encouraged to speak up and stop work if they see unsafe or risky behavior, and has confidence that their concerns and ideas will be heard and pursued. PG&E Corporation and the Utility are committed to significantly improving their safety performance by understanding their risks, prioritizing their work, using controls to reduce risks, and continuously measuring and improving risk reduction.

PG&E Corporation's and the Utility's human capital resource objectives are to build and retain an engaged, well trained, diverse, and equitably-paid workforce. PG&E Corporation and the Utility place a high priority on delivering customer value and providing a hometown customer experience. The Utility's customer-driven investment program is aimed at improving safety, increasing electric and gas reliability, and improving customer satisfaction.

For more information, see "Human Capital" below.

Planet

The planet element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to protect and serve the environment. This commitment extends beyond compliance with various state and federal environmental, health, and safety laws and regulations. PG&E Corporation and the Utility believe that integrating and managing climate change and other environmental considerations in the companies' business strategies creates long-term value for PG&E Corporation and the Utility, and for their customers, communities, coworkers, and other stakeholders. Mitigating and adapting to the impacts of climate change presents opportunities for growth for the Utility's business and economic opportunity for the communities it serves.

The Utility strives to be prepared to continue to deliver safe, clean, affordable, and reliable energy in the face of increasingly severe and extreme climate-driven natural hazards. To build resilience to these hazards, the Utility is working to systematically integrate the consideration of forward-looking climate data and tools in its decision-making. PG&E Corporation and the Utility also work with policymakers and regulators to advance effective climate adaptation policy in California, and work directly with local governments and communities on adaptation solutions.

PG&E Corporation and the Utility have committed to helping heal the planet. PG&E Corporation's and the Utility's Climate Strategy Report, which is available to the public, describes the companies' climate goals and plans to meet those goals. To meet their longer-term climate goals, PG&E Corporation and the Utility intend to scale their efforts to decarbonize the electric system to accommodate a shift to vehicle electrification, integrate a proliferation of distributed energy resources, and achieve increased penetration of renewable energy combined with investments in the grid and energy storage.

PG&E Corporation and the Utility also plan to transition the gas system to cleaner fuels, increasingly target natural gas delivery for hard-to-electrify customer sectors, and support efforts to accelerate building electrification. The objective is to do so in an orderly manner to achieve a positive customer and community experience, while reducing natural gas system investments in targeted electrified communities.

The impacts of climate change on the Utility's infrastructure are already a reality. Record-breaking extreme heat and heat waves are increasingly a regular occurrence throughout California. Peak electric loads are expected to increase with increasing temperatures due to direct impacts of ambient temperatures on equipment and direct impacts on electricity demand driven by rising air conditioning installation and usage, and increasingly driven in the future from widespread progress in adoption of beneficial electrification technologies. The Utility's assets on the coast and in or near watersheds face potential increased exposures to coastal, riverine, and precipitation-related flooding because of climate-driven changes in precipitation and sea-level rise.

Climate change will also continue to intensify the potential for wildfires throughout California. The worsening conditions across California increase the likelihood and severity of wildfires, including those where the Utility's equipment may be alleged to be associated with the fire's ignition. Reducing risk will be even more important as climate change continues to exacerbate the risks facing the Utility. A key element of preparing the Utility for the physical risks of climate change is an updated and more detailed system-wide CVA of the Utility's assets, operations, and services, which the Utility expects to file with the CPUC in 2024. The CVA is expected to improve the Utility's understanding of its exposure to climate hazards and the sensitivity of assets and operations to these hazards.

PG&E Corporation and the Utility continue to pursue policies and programs that enable safe, reliable, and affordable clean and resilient energy for their customers. As a result of actions already taken by PG&E Corporation and the Utility, the companies have:

- Delivered clean electricity to customers in 2022 that was more than 95% GHG free.
- Helped customers avoid emissions and energy costs through robust energy efficiency programs.
- Awarded contracts for more than 3.3 GWs of battery energy storage to be deployed over the next several years, strengthening California's grid efficiency and reliability.
- Installed approximately 340 charging ports for electric vehicles at schools, parks, public charging locations, and in support of fleets - with nearly half in disadvantaged communities - and received regulatory approval for new innovative pilots on vehicle grid integration, submetering, and dynamic rates.
- Brought the total number of interconnected private solar customers to more than 700,000 and supported more than 50,000 customers who have installed battery storage at their homes or businesses.
- Continued to advance decarbonization initiatives for the Utility's natural gas delivery system, including meeting the CPUC-mandated methane emission reduction target ahead of schedule and accelerating initiatives to meet its voluntary 2030 reduction goal.

The CPUC coordinates the planning of supply resources through the Integrated Resource Planning ("IRP") proceeding and has determined that replacing the power generated by Diablo Canyon is the responsibility of all LSEs within the CAISO. Looking ahead, the Utility expects its GHG-free energy supply mix of renewable, large hydroelectric, and nuclear generation resources to decrease as, beginning in 2023, the Utility is required to offer for allocation or sale renewables portfolio standard-eligible ("RPS") attributes that the Utility procured on behalf of customers that subsequently switched to non-Utility providers in order to comply with regulatory mandates and to manage customer affordability. Towards the end of the decade and beyond, the Utility's GHG-free energy supply mix is expected to grow relative to 2025 levels as the Utility procures new GHG-free generation and storage to meet California's IRP GHG emissions reduction targets and California's clean energy goals. For more information, see "Electric Integrated Resource Planning and Related Procurement" below.

Prosperity

The prosperity element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to meeting their financial objectives and providing economic development opportunities and benefits in the communities they serve. Management believes clean energy should be affordable for and inclusive of all economic backgrounds.

Under cost-of-service ratemaking, a utility's earnings depend on the outcomes of its ratemaking proceedings and its ability to manage costs.

See "Ratemaking Mechanisms" below and "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC and FERC proceedings.

Generally, differences between forecast costs and actual costs (discussed in "Utility Revenues and Costs that Impacted Earnings" in Results of Operations in Item 7. MD&A) can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level.

PG&E Corporation and the Utility are committed to taking steps to improve their credit ratings and metrics over time, including by reducing their debt. PG&E Corporation and the Utility have set goals to reduce their debt over time, including reducing PG&E Corporation's debt by at least $2 billion by the end of 2026. PG&E Corporation and the Utility expect that reducing the consolidated debt will help them achieve investment grade credit ratings for their unsecured securities, for the benefit of both customers and investors. For more information, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8. Pursuant to SB 901, 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, which was approved by the CPUC on February 28, 2022. PG&E Wildfire Recovery Funding LLC, a bankruptcy remote, limited liability company wholly owned by the Utility, issued $3.6 billion aggregate principal amount of Series 2022-A Recovery Bonds on May 10, 2022 and $3.9 billion aggregate principal amount of Series 2022-B Recovery Bonds on July 20, 2022. The net proceeds from both transactions were used to reimburse the Utility for previously incurred recovery costs, including the retirement of $5.0 billion of Utility debt and the repayment of a portion of the loans outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement. The Utility intends to use a portion of the remaining proceeds to fund the redemption of $1.0 billion of Utility debt. For more information, see "Application for Post-Emergence Securitization Transaction" in Item 7. MD&A.

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, as well as the Utility's preferred stock. PG&E Corporation's and the Utility's ability to issue dividends is subject to restrictions. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock. On June 15, 2022, the Board of Directors of the Utility also reinstated the dividend on the Utility's common stock. For more information, see "Dividends" in Item 7. MD&A.

Total capital expenditures (including accruals) recorded in 2022 were $9.6 billion. The Utility's total capital expenditures (including accruals) are forecasted to be between $7.9 billion and $11.2 billion for 2023, between $7.9 billion and $12.2 billion for 2024, between $8.0 billion and $12.7 billion for 2025, between $8.1 billion and $13.3 billion for 2026, and between $8.1 billion and $13.8 billion for 2027. The completion of projects, the timing of expenditures, and the associated cost recovery may be affected by permitting requirements and delays, construction schedules, availability of labor, equipment and materials, financing, legal and regulatory approvals and developments, community requests or protests, weather, and other unforeseen conditions.

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The Utility expects to make additional capital expenditures, the recovery of which will be subject to future regulatory approval, including the 2023 GRC. These expenditures include capital expenditures exceeding amounts authorized in the 2020 GRC and 2019 GT&S, and expenditures to be included in a later stage of the 2023 GRC or separate applications. These expenditures are expected to primarily be for wildfire mitigation, transportation electrification, and the Lakeside Building. Additionally, $3.21 billion of fire risk mitigation capital expenditures will be excluded from the Utility's equity rate base pursuant to AB 1054.

PG&E Corporation and the Utility are committed to keeping gas and electric services affordable for all customers. The Utility's capital investment plan, increasing procurement of renewable power and energy storage, increasing environmental regulations, and the cumulative impact of other public policy requirements collectively place continuing upward pressure on customer rates. Certain CPUC proceedings could impact different types of customers differently. Similarly, although the Utility generally recovers its electricity and natural gas procurement costs through rates as "pass-through" costs, commodity prices rose substantially in 2022, relative to 2021. The Utility has set a goal to increase customer capital investments while also limiting customer impacts, including by reducing non-fuel Operating and maintenance costs by two percent per year and by seeking efficient financing. The Utility plans to meet its two percent non-fuel Operating and maintenance cost reduction goal through increased efficiency, including waste elimination through the Lean operating system. The Utility has a number of programs in place to assist low-income customers, such as the CARE program. Under the CARE program, income-qualified customers can receive a monthly discount of 20% or more on their gas and electric bill.

PG&E Corporation's and the Utility's Corporate Sustainability Report, which is available to the public, describes the companies' progress toward world-class performance measured with the triple bottom line framework.

In 2021, the Utility spent $4.01 billion with certified diverse suppliers, representing 38.7% of its total spend.

Performance: Underpinning the Triple Bottom Line

PG&E Corporation and the Utility use the Lean operating system, which includes four basic "plays:" visual management; operating reviews; problem solving; and standard work. Visual management allows teams to see how they are performing against their most important metrics using real-time data. PG&E Corporation and the Utility hold daily, weekly, and monthly operating reviews designed to align the performance of workers closest to the work with the goals and objectives of senior leadership. These brief meetings help the Utility identify gaps and quickly develop plans to support the teams performing the work and give the Utility more visibility, control and predictability in its operations. Problem solving involves a structured approach to identifying, containing, analyzing, and solving problems in order to capitalize on opportunities. Standard work reduces costs and increases productivity by ensuring a consistent company-wide method for completing a task. For instance, the Lean operating system helped the Utility identify patterns in the conditions of ignitions and led to the implementation of EPSS and drove significant benefit and understanding in how PG&E Corporation and the Utility manage customer satisfaction. PG&E Corporation's and the Utility's performance is also driven by an increased focus on alignment on shared outcomes among its leadership and within the organization. In 2023, PG&E Corporation's and the Utility's Lean deployment will focus on a fifth play, waste elimination, which enables the companies to identify and eliminate inefficiencies in both process and workflow in a sustainable manner, as well as the continued adoption of a performance playbook and improvements to financial visibility and controls.

PG&E Corporation and the Utility have implemented a regional service model to bring the Utility closer to the hometowns it serves. Through the regional service model, the Utility has restructured its service area into five regions, with leaders in each region to deliver improved public and employee safety, customer service, and operational reliability outcomes.

PG&E Corporation and the Utility are committed to designing an electric system that is resilient to climate change, decarbonized, and optimized to local and system needs.

California has experienced unprecedented weather conditions in recent years and the Utility's service area remains susceptible to additional wildfire activity. In response, the Utility has implemented operational changes and investments that reduce wildfire risk, including:

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Enhanced Powerline Safety Settings:

EPSS adjusts the sensitivity of circuit protection devices on selected power lines to de-energize them more rapidly in the event of a disturbance to help prevent potential ignitions. After EPSS was initiated, both the size and number of CPUC-reportable ignitions were reduced substantially on EPSS-enabled circuits, compared to the prior three-year average.

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Public Safety Power Shutoffs:

The PSPS program proactively de-energizes power lines in response to forecasted weather conditions. Since its inception in late 2017, the PSPS program has become more targeted because the Utility has developed more granular risk models, including adding consideration of vegetation management and maintenance tag statuses for scoping PSPS events. The Utility has also installed sectionalizers for more targeted de-energizations of circuits and transmission lines. In 2022, the Utility did not have any PSPS events.

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Vegetation management:

The Utility inspects its overhead electric distribution and transmission facilities on an annual basis to identify and clear vegetation that might grow or fall into utility equipment. The Utility is also increasing oversight and engagement with the contractors supporting vegetation management work.

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Asset inspections:

Since 2018, the Utility has reoriented its asset inspections programs toward asset condition and consequence risk, particularly wildfire risk, and these programs have become more thorough, standardized, digitized, and verifiable. The Utility uses risk-informed inspection cycles. In 2022, the Utility continued to refine its risk modeling, including further incorporating data from asset inspections. As a result of the improved inspection program, the Utility's inspections in recent years have begun to more thoroughly identify equipment conditions.

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System hardening:

System hardening entails repairing, replacing, or eliminating existing power lines in HFTDs and installing stronger and more resilient equipment. As the Utility's asset inspections have identified more equipment conditions, the Utility has hardened its system by correcting significantly more equipment conditions than in prior years. Hardening methods include replacing bare overhead conductor with covered conductor and installing stronger poles, removing lines, and serving customers through remote grids, or converting lines from overhead to underground. In 2021, the Utility announced a program to underground 10,000 miles of electric distribution lines in high wildfire risk areas. In 2022, the Utility undergrounded 180 miles of lines, which exceeded its plan to underground 175 miles of lines. Undergrounding can substantially reduce ignition risk and improve reliability during storms or periods of high wildfire risk. The Utility also brought online two additional "remote grids" in 2022, which allow distribution lines in HFTDs to be removed and replaced with locally sited resources. Remote grids can reduce costs and fire risks, while maintaining service to participating customers.

As a result of these measures, the Utility significantly reduced both the size and number of CPUC-reportable ignitions and number of acres burned in 2022, compared to prior years.

Even as the Utility works to mitigate wildfire risk, it also works to reduce the impact of those mitigations on its customers, including making the PSPS program less disruptive through sectionalizing devices for both distribution and transmission lines, temporary generation applications, and implementation of microgrids which enable portions of the grid to safely isolate areas from the broader grid and energize them during outages. For example, in 2022, the Utility prepared 12 distribution microgrids to operate with temporary generation if needed.

In 2022, the Utility expanded the EPSS program to all high fire risk areas. In addition, the Utility uses multiple weather models on a daily basis that indicate which circuits to enable with safety settings and which to put in normal protection settings, optimizing for maximum wildfire ignition risk reduction when needed and enhancing reliability benefits when wildfire risk is low. In 2022, the Utility also began reviewing and adjusting settings to improve coordination among devices on a circuit to reduce the number of customers impacted by an outage. In 2023, the Utility will expand its deployment of advanced technology to detect low-current faults, which is expected to further decrease wildfire ignition risk.

PG&E Corporation and the Utility are continuing to invest in a safe and reliable gas system and are working toward targeted electrification, greening the gas supply, and shaping California energy policy. The Utility has focused on continuously improving its gas operations safety record. Since the San Bruno natural gas pipeline explosion in 2010, the Utility's asset safety efforts have included replacing distribution mains and transmission pipelines, as well as strength testing transmission pipelines. The Utility uses in-line inspections to assess the integrity of transmission pipelines. The Utility also uses safety and control systems to monitor, gather, and process real-time data on its gas system. In 2022, the Utility's gas operations had two workforce serious injuries and fatalities ("SIF-A") incidents and reductions in the number of injuries that result in days away, restricted or transferred duty per 200,000 hours worked ("DART"). The Utility's gas system has not had a safety-related incident that affected the public and resulted in a fatality or injury since 2015 or 2018, respectively.

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The Utility has engaged in educating employees, contractors, and the public regarding safe digging programs and practices for their awareness during construction and when digging near the Utility's underground gas and electric assets. The Utility also installed safety devices that automatically detect increasing pressure on systems and stop the flow of gas to avoid outages and overpressure events. Additionally, the Utility continues to streamline its efforts to respond to outages on a timely basis. The Utility's outage response is designed to keep the public safe while limiting customer outages and returning service safely and as quickly as possible.

The Utility's generation operations have focused on safety and reliability. In 2022, the Utility's nuclear and non-nuclear generation operations achieved zero SIF-A incidents and reductions in DART. Challenged by a drought year, the Utility scheduled dispatch and rescheduled outages to maximize availability during the summer months when demand for electricity is highest. The Utility is working to implement a comprehensive non-nuclear generation asset management strategy and further mature its outage and project management capabilities.

In 2022, the Utility achieved International Organization for Standardization ("ISO") 55001 certification for its electric operations and generation asset management systems. The Utility also achieved ISO 55001 re-certification for its gas operations asset management. ISO 55001 certification required the Utility to demonstrate that it has policies and procedures to manage its assets responsibly and effectively.

Regulatory Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is regulated primarily by the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies, including with respect to safety, the environment, and health, such as the NTSB and OEIS.

This section and the "Environmental Regulation" and the "Ratemaking Mechanisms" sections below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. For more information, see Item 1A. Risk Factors and "Regulatory Matters" in Item 7. MD&A.

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

California Public Utilities Commission

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

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $100,000 per day, per violation. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations, the type of harm caused by the violations and the number of persons affected, and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and electric citation programs adopted by the CPUC in September 2016, the SED has discretion whether to issue a penalty for each violation; but if it assesses a penalty for a violation, it has the authority to impose the maximum statutory penalty of $100,000 per day, with an administrative limit of $8 million per citation issued. Similar to penalties imposed by the CPUC, penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders of an issuer and may not be recovered in rates or otherwise directly or indirectly charged to customers.

The CPUC has also authorized the SED to propose for CPUC approval administrative consent orders and administrative enforcement orders when the SED deems a formal OII unnecessary.

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

The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation's Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. For more information on specific CPUC enforcement matters and CPUC-implemented laws and policies and the related impact on PG&E Corporation and the Utility, see Item 1A. Risk Factors, and "Regulatory Matters," "Legislative and Regulatory Initiatives" and "Liquidity and Financial Resources" in Item 7. MD&A and Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Federal Energy Regulatory Commission and California Independent System Operator Corporation

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility's transmission systems with other electric systems and generation facilities, the tariffs and conditions of service of regional transmission organizations, and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electric transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. The FERC's approval is also required under Federal Power Act Section 203 before undertaking certain transactions, including most mergers and consolidations, certain transactions that result in a change in control of a utility, purchases of utility securities and dispositions of utility property. The FERC has authority to impose fines of up to $1 million per day for violations of certain federal statutes and regulations. For more information on specific FERC requirements and their impact on PG&E Corporation and the Utility, see Item 1A. Risk Factors, and "Regulatory Matters," "Legislative and Regulatory Initiatives" and "Liquidity and Financial Resources" in Item 7. MD&A and Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

The CAISO is the FERC-approved regional transmission organization for the Utility's service area. The CAISO controls the operation of the electric transmission system in most of California and a small part of Nevada and provides open access transmission service on a non-discriminatory basis. The CAISO is also responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, ensuring that the reliability of the transmission system is maintained, and operating the wholesale power market in most of California and an interstate energy imbalance market.

Nuclear Regulatory Commission

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. See "Electricity Resources" below. NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. For more information about Diablo Canyon, see Item 1A. Risk Factors and Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Other Regulators

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

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

The NTSB is an independent U.S. government investigative agency responsible for civil transportation accident investigations, including pipeline accidents. The NTSB also conducts special investigations and safety studies, and issues safety recommendations to prevent future accidents.

The California Geologic Energy Management Division is the state agency responsible for establishing and enforcing regulations for the operation of the Utility's underground gas storage facilities.

The OEIS is a state agency responsible for reviewing and approving the Utility's WMP and for evaluating the Utility's implementation of the WMP. The OEIS is also responsible for reviewing and issuing the Utility's annual safety certification, annually reviewing and approving the Utility's executive compensation plan, conducting assessments of the Utility's safety culture, and conducting field inspections of wildfire mitigation activities.

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the

Utility's electric and natural gas facilities in the public streets and highways. In exchange for the right to use public streets and highways, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. For more information see Item 1A. Risk Factors.

Material Effects of Compliance with Governmental Regulations

As indicated above, the Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. Compliance with such extensive government regulations requires substantial expenditures and has had in the past and may continue to have in the future a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, cash flows and competitive position. For more information about costs incurred to comply with government regulations and related material effects on PG&E Corporation and the Utility, see Item 1A. Risk Factors, "Regulatory Matters" in Item 7. MD&A, and Notes 15 and 16 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental Regulation

The Utility's operations are subject to extensive federal, state, and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of CO_2 and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. See Item 1A. Risk Factors. Generally, the Utility recovers most of the costs of complying with environmental laws and regulations through the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Hazardous Substance Compliance and Remediation

The Utility's facilities are subject to various regulations adopted by the EPA, including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended. The Utility is also subject to the regulations adopted by other federal agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act, these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former MGP sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Air Quality and Climate Change

The Utility's electric generation plants, natural gas pipeline operations, vehicle fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, and other emissions.

Federal Regulation

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

Tackling the climate crisis is a key priority of the Biden Administration, and the Administration has signaled its intent to use its executive and regulatory authorities to reduce emissions in line with science-based targets. On January 20, 2021, President Biden issued an executive order directing the EPA to consider suspending, revising or rescinding the Trump Administration's rule for methane emissions from new sources in the oil and gas sector and propose a companion regulation for existing sources, including the transmission, processing and storage segments of the industry. For power plants, the EPA is expected to propose a more stringent GHG standard for existing sources in the wake of challenges to the Trump Administration's Affordable Clean Energy rule.

State Regulation

California's Global Warming Solutions Act of 2006 originally provided for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy.

The cap-and-trade program applies to the electric generation, large industrial, natural gas, petroleum, and transportation sectors. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than large natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation.

The cap-and-trade program has been extended through 2030. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Entities with a compliance obligation can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Complying entities may also satisfy a portion of their compliance obligation through the purchase of offset credits (e.g., credits for GHG reductions achieved by third parties, such as landowners, livestock owners, and farmers, that occur outside of the entities' facilities through CARB-qualified offset projects such as reforestation or biomass projects). The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers.

California law requires that the CARB ensure a 40% reduction in GHGs by 2030 compared to 1990 levels. The California RPS program that requires utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California. California's RPS targets are 50% by December 31, 2026 and 60% by December 31, 2030, and the State has set a policy of meeting 100% of retail sales from eligible renewables and zero-carbon resources by December 31, 2045. In 2022, AB 1279 was signed into law, codifying a statewide goal to achieve economy-wide carbon neutrality by 2045 and to maintain net negative emissions thereafter. Additionally in 2022, SB 1020 established targets that renewable and zero-carbon resources will supply 90% of utilities' retail sales to customers by 2035 and 95% of retail sales by 2040. The Utility will be an active participant in regulatory proceedings to determine how the state will achieve carbon neutrality. For the percentage of the Utility's estimated total net deliveries of electricity to customers in 2022, including estimated GHG-free and renewable energy percentages, see "Electric Utility Operations-Electricity Resources" below.

Climate Change Resilience Strategies

Mitigating Greenhouse Gas Emissions

During 2022, the Utility continued its programs to mitigate the impact of the Utility's operations (including customer energy usage) on the environment, consistent with the Utility's commitment to a healthy environment and carbon neutral-energy system for all Californians.

Adapting to the Physical Impacts of Climate Change

Effectively managing physical climate risk will become increasingly critical as the physical impacts of climate change become increasingly frequent and severe over the coming years in California. The Utility's climate resilience efforts continue to focus on characterizing and mitigating the physical impacts of climate change to the Utility's infrastructure, assets, and operations. The Utility is making substantial investments to build a more resilient system that can better withstand extreme weather and related emergencies. For more information on such investments, see "Performance: Underpinning the Triple Bottom Line" above.

The Utility's preparations for the physical risks of climate change include an updated, more detailed, system-wide CVA of the Utility's assets, operations, and services, which will be completed in 2024 and filed with the CPUC. The updated CVA will improve the Utility's understanding of its exposure to climate hazards in the near- and long-term and the sensitivity of assets and operations to these hazards. It will also inform the Utility's understanding of the ease or difficulty of various options for adapting to changing conditions.

In the past few years, the Utility's electric distribution system has experienced multiple major outage-causing events associated with extreme heat events and peak loads. Peak loads are expected to increase with increasing temperatures due to direct impacts of ambient temperatures on equipment and direct impacts on electricity demand driven by rising air conditioning installation and usage.

The Utility's assets on the coast and in or near watersheds face potential increased exposures to coastal, riverine (fluvial), and precipitation related (pluvial) flooding because of climate-driven changes in precipitation and sea level rise. The risk of damage to or interruptions of operations at facilities such as substations is predicted to increase over time due to sea level rise. Electric and gas equipment and safe access for operations must be prepared for these changing conditions.

Changing precipitation dynamics may impact the Utility's hydroelectric generation. Diminishing future water availability and altered runoff timing during extreme drought poses risks to hydropower generation, operations, and revenue. Also, extreme rain events suggest enhanced risk of hydropower asset damage or failure associated with flooding, which in the worst cases (e.g., uncontrolled water release) may have catastrophic impacts.

Climate change will also continue to intensify the potential for wildfires throughout California. Models incorporating future temperature and precipitation projections suggest that landscape susceptibility to wildfire within the Utility's service area will continue to increase over time, with an expansion of areas that may become HFTD and an intensification of risk within HFTDs. Climate change may also result in increased potential of lines to cause ignitions or to require PSPS events, as well as the potential for the Utility's equipment to sustain damage from wildfires of any origin.

The Utility's updated CVA will be used to inform changes to design and construction standards for equipment and facilities to increase infrastructure resilience to current and future extreme weather conditions. Results from the updated CVA will be incorporated into the Utility's key risk and planning functions, as well as asset management strategy, to identify priority adaptive actions.

The Utility is also engaging with CPUC-designated disadvantaged and vulnerable communities throughout the CVA process to ensure that customer perspectives regarding energy system resilience are part of updating the CVA. The Utility is conducting regional community engagement campaigns throughout its service area to understand how some of the most vulnerable communities the Utility serves think about climate hazards and adaptation. This information will help the Utility plan adaptive climate action aligned with customer and community perspectives.

In addition to updating the CVA, the Utility regularly reviews relevant scientific literature regarding climate change to incorporate appropriate information into its operations. For example, based on a recent report about potential major atmospheric river events, the Utility updated and modified its flooding emergency response plan.

The Utility's commitment to increasing resilience to climate change includes aligning its resources and business strategy with California's clean energy goals, the Utility's climate strategy, and advocating for policies and programs that enable safe and reliable energy for the Utility's customers in light of climate change. For example, the Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage will help it adapt to the expected increases in demand for electricity.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2021, which is the most recent data available, totaled Scope 1 and 2 emissions of approximately 4.6 million metric tons of CO_2 equivalent (MMT CO_2

e) and Scope 3 emissions of approximately 42 MMT CO_2e, the majority of which came from customer natural gas use.

The following table shows the 2021 GHG emissions data the Utility reported to the CARB, which is the most recent data available. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Sustainability Report.

Source	Amount (metric tons CO_2 equivalent)
Fossil fuel-fired plants (1)	2,485,379
Natural gas compressor stations and storage facilities (2)	322,047
Distribution fugitive natural gas emissions	589,343
Customer natural gas use (3)	41,563,483

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

(2) Includes emissions from compressor stations and storage facilities that are reportable to CARB.

(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's

distribution system, with the exception of gas delivered to other natural gas local distribution companies.

The Utility utilized the CEC's Power Source Disclosure program methodology to calculate the CO_2 emissions rate associated with the electricity delivered to retail customers in 2021. This resulted in a third-party verified CO_2 emissions rate of 99 pounds of CO_2 per MWh.

Air Emissions Data for Utility-Owned Generation

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Sustainability Report.

	2021	2020
Total NOx emissions (tons)	139	141
NOx emissions rate (pounds/MWh)	0.01	0.01
Total SO_2 emissions (tons)	14	15

SO

2

emissions rate (pounds/MWh)

0.001

0.001

22

Nuclear Fuel Disposal

Nuclear power plant operations produce gaseous, liquid, and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools, and equipment contaminated through use.

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the DOJ and the Utility executed a settlement agreement that provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. The claim for the period June 1, 2021 through May 31, 2022, totaled approximately $10.5 million and is under review by the DOE. Amounts reimbursed by DOE are refunded to customers through rates. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

Ratemaking Mechanisms

The Utility operates under a "cost-of-service" ratemaking model, which means that rates for electric and natural gas utility services are generally set at levels that are intended to allow the Utility to recover its costs of providing service and to earn a return on invested capital ("cost-of-service ratemaking"). In order to set rates, the CPUC and the FERC conduct proceedings to determine the amount that the Utility will be authorized to collect from its customers ("revenue requirements"). In the GRC proceedings, the CPUC also generally approves the level of capital spending on a forecasted basis. Revenue authorized by the CPUC through GRC proceedings is intended to provide the Utility a reasonable opportunity to recover its costs and earn a return on its investments in generation and distribution assets and general plant (also referred to as "rate base"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, and financing expenses).

The Utility's costs of equity and long-term debt are generally approved in the CPUC's cost of capital proceedings. In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A), including its costs to procure electricity and natural gas for customers and to administer public purpose and customer programs. FERC revenue requirements are set through a FERC-approved formula rate.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. Other than certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume through certain regulatory balancing accounts, or revenue adjustment mechanisms, that are designed to allow the Utility to collect its authorized base revenue requirements regardless of sales volume. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from, for example, weather or economic conditions. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

Due to the seasonal nature of the Utility's business and rate design, customer electric bills are generally higher during summer months (May to October) because of higher demand, driven by air conditioning loads. Customer bills related to gas service are generally higher during winter months (November to March) because of higher demand due to heating.

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs.

See "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC proceedings.

Base Revenues

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs related to its electric distribution, natural gas distribution, and Utility-owned electric generation operations and return on rate base. In the past, the CPUC has generally conducted a GRC every three years. Starting with the 2023 GRC, the CPUC now conducts a GRC every four years that includes the Utility's costs of its gas transmission and storage facilities. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally authorized for cost increases related to invested capital and inflation. Parties in the Utility's GRC include the Public Advocates Office of the CPUC (formerly known as Office of Ratepayer Advocates or ORA) and TURN, which generally represent the overall interests of residential customers, as well as numerous intervenors that represent other business, community, customer, environmental, and union interests. For more information about the Utility's GRC, see

"Regulatory Matters - 2023 General Rate Case" in Item 7. MD&A.

Cost of Capital Proceedings

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC's cost of capital proceedings generally take place in a consolidated proceeding with California's other large investor-owned electric and gas utilities. For more information about the cost of capital proceedings, see "Regulatory Matters - Cost of Capital Proceedings" in Item 7. MD&A.

Electricity Transmission Owner Rate Cases

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. In its TO rate cases, the Utility uses a formula rate methodology, which includes an authorized revenue requirement and rate base for a given year but also provides for an annual update of the previous year's revenue requirement and rates in accordance with the terms of the FERC-approved formula. Under the formula rate mechanism, transmission revenue requirements are updated to the actual cost of service annually as part of the true-up process. Differences between amounts collected and determined under the formula rate are either collected from or refunded to customers. The FERC-approved formula rate will be effective through December 31, 2023. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and by the CAISO in its transmission access charges to wholesale customers. For more information, see "Regulatory Matters - Transmission Owner Rate Cases" in Item 7. MD&A. The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

Program-Specific Memorandum Account and Balancing Account Costs

Periodically, costs arise outside of the CPUC GRC proceedings or that have been deliberately excluded therefrom. These costs may result from catastrophic events, changes in regulation, new programs, 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 reasonable. For instance, these accounts allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. Recovery of the costs tracked in these memorandum accounts in rates requires CPUC authorization in separate proceedings for which the Utility may be unable to predict the outcome. Alternatively, the Utility may seek authority to track incremental costs related to these non-GRC programs in balancing accounts. The CPUC may authorize recovery of costs tracked in the balancing accounts on either a "one-way" basis, which typically only allows actual costs to be recovered up to a pre-established cap, or a "two-way" basis, which typically allows actual costs to be recovered, and in some cases subject to further CPUC review. For more information, see "Regulatory Matters - Cost Recovery Proceedings" in Item 7. MD&A and Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

Revenues to Recover Energy Procurement and Other Pass-Through Costs

Electricity Procurement Costs

California IOUs are responsible for procuring electrical capacity required to meet bundled customer demand, plus applicable reserve margins. The utilities are responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their Bundled Procurement Plans ("BPPs") based on long-term demand forecasts. In October 2015, the CPUC approved the Utility's most recent comprehensive BPP. It has been revised since its initial approval, and the revised version will remain in effect, subject to any further revisions, until superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their

CPUC-approved BPPs without further after-the-fact reasonableness review by the CPUC. The CPUC may disallow costs associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch. Additionally, the CPUC may disallow the value of lost generation due to unplanned outages at utility-owned generation facilities.

The Utility recovers its electric procurement costs annually primarily through balancing accounts. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8. Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electric rates more frequently if the forecasted aggregate over-collections or under-collections in the Energy Resource Recovery Account, net of bundled service customer Portfolio Allocation Balancing Account balances, exceed five percent of its prior year electric procurement and Utility-owned generation revenues. The CPUC performs an annual compliance review of the procurement transactions recovered in various balancing accounts, including the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved BPP, to meet mandatory renewable energy targets, and to comply with RA requirements. For more information, see "Electric Utility Operations - Electricity Resources" below as well as Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility is also responsible, as the central procurement entity ("CPE") for its distribution service area, for seeking to procure the entire amount of required local RA on behalf of all CPUC-jurisdictional LSEs in its distribution service area. CPUC decisions grant the Utility, acting as CPE, discretion to defer procurement of local resources to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high. The Utility, as the CPE, will not be assessed fines or penalties for failing to procure resources to meet the local RA requirements and deferring local procurement to the CAISO backstop mechanism, as long as the CPE exercised reasonable efforts to secure capacity and certain specified requirements are met. In addition, the Utility, as the CPE, has been ordered or authorized to seek to procure specific local capacity products pursuant to CPUC decisions. In connection with its CPE function, the Utility is responsible for making compliance demonstrations to the CPUC and the CAISO. The Utility recovers its administrative and procurement costs associated with its CPE function through a balancing account. Each year, the CPUC reviews the Utility's forecasted administrative costs related to the CPE function and approves a forecasted revenue requirement associated with the administrative costs. The CPUC performs an annual compliance review of the CPE function, including procurement transactions with terms of five years or less (for which costs incurred in compliance with certain prescribed criteria are deemed reasonable and pre-approved without further after-the-fact reasonableness review). Procurement transactions with terms exceeding five years are reviewed separately. The CPUC may disallow costs associated with the CPE function that were not incurred in compliance with the CPUC's decisions and guidance.

The CPUC has also approved the Power Charge Indifference Adjustment ("PCIA"). The PCIA is a cost recovery mechanism to ensure that customers who switch from the Utility's bundled service to a non-Utility provider, such as a DA or CCA provider, pay their share of the above market costs associated with long-term power purchase commitments and Utility-owned generation made on their behalf.

Natural Gas Procurement, Storage, and Transportation Costs

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electric rates.

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

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

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

Costs Associated with Public Purpose and Customer Programs

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide discounted rates for specified types of customers, such as for low-income customers under the CARE program, which is paid for by the Utility's other customers.

Nuclear Decommissioning Costs

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Nuclear decommissioning costs are generally collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility's updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility's nuclear plants. If the nuclear decommissioning trusts are overfunded, the amount of such overfunding will be returned to customers. Pursuant to Public Utilities Code Section 8325, to the extent the monies available for decommissioning are insufficient to pay for all reasonable and prudent decommissioning costs, the CPUC must authorize the electric utility to collect these charges from its customers.

For costs related to AROs see "Asset Retirement Obligations" in Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

Human Capital

Employees and Contractors

As of December 31, 2022, PG&E Corporation had 10 employees and the Utility had approximately

26,000 regular employees. Of the Utility's regular employees, approximately 16,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW") Local 1245; the Engineers and Scientists of California ("ESC") IFPTE 20; and the Service Employees International Union Local 24/7 ("SEIU"). The collective bargaining agreements in effect for the IBEW Local 1245; ESC Local 20; and SEIU, United Service Workers West will expire on December 31, 2025. The agreements increase wages annually by 3.75% from 2022 through 2025 and maintain current contributions to specified benefits. The IBEW, ESC, and SEIU represent approximately 62% of the Utility's employee workforce and support several areas of the Utility's business, including gas and electric operations. The Utility enjoys stable and productive relationships with its unions and did not experience any work stoppages in 2022.

PG&E Corporation's employees are primarily at the executive management level, which experienced significant employee turnover throughout the course of its Chapter 11 Cases in 2019 and 2020. The Utility generally has a stable workforce, which translated into low voluntary turnover during that period. The Utility's turnover rates for 2022 and 2021 were 7.1% and 5.8%, respectively. Approximately 42% of PG&E Corporation's and the Utility's employees have a tenure of more than 10 years, with an average tenure of 11 years. Approximately 19% of PG&E Corporation's and the Utility's employees are eligible to retire. (PG&E Corporation and the Utility define retirement age as 55 years and older.)

The Utility's contractors and subcontractors include approximately 42,000 individuals from approximately 1,200 contractor companies.

Human Capital Management

PG&E Corporation's and the Utility's human capital resource objectives are to build and retain an engaged, well trained, diverse, and equitable workforce. PG&E Corporation's and the Utility's Boards of Directors are responsible for overseeing management's development and execution of PG&E Corporation's and the Utility's human capital strategy.

To build employee engagement, the Utility has a variety of both executive-level and employee-led initiatives and programs. PG&E Corporation's and the Utility's executive teams meet regularly to discuss and evaluate the state of employee talent, determine which programs are driving engagement and performance, and clarify the specific skills, behaviors, and values that should be cultivated. Each year, the Utility honors employees whose work embodies safety, diversity, equity, inclusion, belonging, environmental leadership, and community service. The Utility conducts an annual employee engagement survey to measure and improve employee engagement progress.

Every year, PG&E Corporation and the Utility offer or require technical, leadership, and employee training, which includes a range of technical training for employees on the knowledge and skills required to perform their jobs safely using approved tools and work procedures. In addition, employees are required to complete an annual compliance and ethics training and a Code of Conduct training, both of which are intended to promote a culture in which employees are encouraged to speak up with any concerns or ideas for continuous improvement. In addition, the Utility offers a variety of other trainings and education opportunities.

Among other programs, the Utility provides career opportunities through its PowerPathway(TM) workforce development program. Launched in 2008, PowerPathway is a workforce development model to enlarge the talent pool of local, qualified, diverse candidates for skilled craft and utility industry jobs through training program partnerships with educational, community-based and government organizations. PowerPathway helps people throughout the Utility's service area, including women and military veterans, prepare and compete for high demand jobs in the utility and energy industry. Students receive approximately eight weeks of industry-informed curriculum to ensure the academic, job specific, employability skills and physical training necessary to effectively compete for entry-level employment. Programs may also include hands-on training and on-the-job training.

PG&E Corporation and the Utility also provide integrated solutions and programs that cover employee health and wellness and that encompass physical, emotional, and financial health, including an on-site health clinic, an annual health screening, and health management tools and resources, in addition to more traditional programs.

PG&E Corporation's and the Utility's financial incentives offered to employees include a Short-Term Incentive Plan ("STIP"), an at-risk part of employee compensation designed to reward eligible employees for achieving specific performance goals. The 2022 STIP was focused on company objectives of safety, customer impact, and financial health.

All PG&E Corporation and Utility officer compensation currently is funded by shareholders.

Safety

The Utility's strategy to deliver on safety outcomes focuses on workforce, and public safety. In 2023, in addition to deploying the safety management system, the Utility targets mitigations to the highest risk work. The Utility's safety metrics include the number of SIF-A incidents and the SIF-P rate, which measures events that could have resulted in a SIF-A per 200,000 hours worked. In 2022, the Utility had seven SIF-A incidents, which resulted in three fatalities and four serious injuries, and a SIF-P rate of 0.11. Additionally, the Utility measures DART. In 2022, the Utility's DART was 0.67, which was 34% lower than in 2021 and its lowest rate in the past five years.

Throughout the COVID-19 pandemic, PG&E Corporation and the Utility have continued to monitor activities at the Centers for Disease Control and Prevention and the World Health Organization. PG&E Corporation and the Utility have updated their protocols and actions in accordance with guidance from these organizations, following state and local health and safety regulations, and in consultation with the Utility's medical director. PG&E Corporation and the Utility have also remained focused on protecting the health and safety of their employees, contractors and the Utility's customers, while continuing to perform critical utility work, and have continued to monitor and track the impact of the pandemic, modifying or adopting new policies in support of their employees' health and safety as pandemic conditions and governmental response have changed.

Diversity, Equity, Inclusion, and Belonging

PG&E Corporation's and the Utility's goal is to foster a diverse, equitable, and inclusive environment that enables all of their coworkers to bring their best selves to work so that they can provide exceptional customer service. These efforts are led by PG&E Corporation's and the Utility's

Executive Vice President, People, Shared Services and Supply Chain, with support from the executive team. The People and Compensation Committee of PG&E Corporation's Board of Directors reviews the companies' diversity, equity, inclusion, and belonging practices and performance.

Key elements of PG&E Corporation's and the Utility's approach include active programming to heighten cultural competency, encourage understanding and appreciation of diversity, and integrate thoughtful content into training and performance support materials.

Additionally, the Utility's 11 Employee Resource Groups and three Engineering Network Groups execute enterprise-wide available programming, certain coworkers lead efforts within their departments, and other specialized teams facilitate dialogue across the companies. These efforts foster employee belonging and support an environment of inclusion that values and respects diversity in the workforce.

In 2022, women, minorities, and military veterans accounted for approximately 26%, 49% and 7%, respectively, of total PG&E Corporation and Utility employees. Approximately 8% of the Utility's employees are younger than 30, 62% are between the ages of 30 and 49, and 30% are 50 or older.

Electric Utility Operations

The Utility generates electricity and provides electric transmission and distribution services throughout its service area in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides electricity, transmission and distribution services in its service area. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations. For more information, see "Regulatory Matters" in Item 7. MD&A.

Electricity Resources

The Utility is required to maintain adequate capacity to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand.

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The following table shows the percentage of the Utility's estimated total net deliveries of electricity to customers in 2022 represented by each major electric resource, and further discussed below. The Utility's deliveries were primarily from renewable energy resources that qualify under California's RPS and other GHG-free resources (i.e., nuclear, and large hydroelectric generation). California's RPS requirements and SB 100 goal to serve 100% of retail electricity sales with GHG-free resources by 2045 are discussed further below and in the Environmental Regulation section above.

The total estimated electricity generated, procured, and sold (net), as of December 31, 2022 was 30,307 GWh

(1)

and comprised of the following:

Percent of customer retail sales (estimated procurement)

CEC reporting methodology adjustment

(2)

Percent of customer retail sales (estimated Power Content Label)

(2)

Owned generation facilities

Renewable

(3)

2

%

--

%

2

%

Nuclear

49

%

--

%

49

%

Large hydroelectric

7

%

--

%

7

%

Fossil fuel-fired

(4)

18

%

(16)

%

2

%

Total

76

%

(16)

%

60

%

Third-party purchase agreements

Renewable

(3)

38

%

--

%

38

%

Large hydroelectric

--

%

--

%

--

%

Fossil fuel-fired

(4)

16

%

(14)

%

2

%

Total

54

%

(14)

%

40

%

Others, net

(2)(5)

(30)

%

30

%

--

%

TOTAL

100

%

--

%

100

%

Total renewable energy resources

(3)

40

%

--

%

40

%

GHG-free resources

(6)

96

%

--

%

96

%

(1)

This amount excludes electricity provided by DA providers and CCAs that procure their own supplies of electricity for their respective customers.

(2)

The allocation of "Others, net" in the "CEC Reporting Methodology Reduction" and "Power Content Label" columns is consistent with CEC guidelines, applied to specified electric generation and procurement volumes (i.e., fossil fuel-fired, nuclear, large hydroelectric, and renewable). Total reported generation and procurement volumes equate to actual electric retail sales.

(3)

Amounts include biopower (e.g., biogas, biomass), solar, wind, certain hydroelectric (i.e., 30MW or less), and geothermal facilities. The eligible renewable percentages above do not reflect RPS compliance, which is determined using a different methodology.

(4)

Amounts consist primarily of natural gas facilities.

(5)

Amount is mainly comprised of net CAISO open market (sales)/purchases.

(6)

Amount is comprised of renewable, nuclear, and large hydroelectric facility resources generated, procured, and sold.

Renewable Energy Resources

California law established an RPS that requires LSEs, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers. SB 350 increased the amount of renewable energy that must be delivered by most LSEs, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028-2030 compliance period, and in each three-year compliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. In September 2018, the California Governor signed SB 100 into law, increasing from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and established state policy that 100% of all retail electricity sales must come from RPS-eligible or carbon-free resources by 2045. The Utility may in the future incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable through rates as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets.

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Renewable generation resources, for purposes of the RPS requirements, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. RPS requirements are based on procurement, which aligns with the methodology presented in the first column of the table above. Procurement from renewable energy sources was estimated to comprise 40% of total annual retail sales in 2022.

The estimated total renewable deliveries as of December 31, 2022, shown above was 12,163 GWh and comprised of the following:

Type

Percent of Customer Retail Sales (estimated procurement)

(1)

(2)

Biopower

5

%

Geothermal

--

%

RPS-Eligible Small Hydroelectric

2

%

Solar

24

%

Wind

9

%

Total

40

%

(1)

Estimated renewable procurement amounts are expected to be consistent with Power Content Label reporting and adjustments, based on current CEC guidelines.

(2)

Estimated renewable procurement percentages above and renewable compliance percentages are expected to be consistent; however, final RPS compliance reporting is subject to a different methodology and may result in some differences between the two percentages.

Energy Storage

Energy storage improves system reliability and supports California's decarbonization goals by integrating increased levels of renewable energy. The CPUC has established a multi-year energy storage procurement framework, under which the Utility was required to procure 580 MW of qualifying storage capacity by the end of 2020, with all energy storage projects required to be operational by the end of 2024. As of December 31, 2022, the Utility was on track to meet its storage goals by the end of 2024.

Additionally, the Utility has been actively procuring energy storage to meet critical reliability needs.

The CPUC previously approved more than 1,100 MW of storage to come online in 2022 and 2023. In January 2022, the Utility also requested CPUC approval for another 1,600 MW of storage to be completed by the summer of 2024, which would bring the Utility's total energy storage system capacity to more than 3,330 MW. Finally, the Utility is soliciting 200 MW of long-duration storage, which is storage with at least eight hours of discharge capacity, to have these resources online between 2026 and 2028.

Owned Generation Facilities

At December 31, 2022, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Nuclear (1):			
Diablo Canyon	San Luis Obispo	2	2,240
Hydroelectric (2):			
Conventional	16 counties in northern and central California	99	2,645

Helms pumped storage

Fresno

3

1,212

Fossil fuel-fired:

Colusa Generating Station

Colusa

1

657

Gateway Generating Station

Contra Costa

1

580

Humboldt Bay Generating Station

Humboldt

10

163

Elkhorn Battery Energy Storage System

Monterey County

1

183

Photovoltaic

(3)

:

Various

13

152

Total

130

7,832

(1)

The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses currently expire in 2024 and 2025, respectively. For more information, see "Extension of Diablo Canyon Operations" in Item 7. MD&A below.

(2)

The Utility's hydroelectric system consists of 102 generating units at 63 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to the FERC's licensing requirements), with license terms between 30 and 50 years.

30

(3)

The Utility's large photovoltaic facilities are Cantua solar station (20 MW), Five Points solar station (15 MW), Gates solar station (20 MW), Giffen solar station (10 MW), Guernsey solar station (20 MW), Huron solar station (20 MW), Stroud solar station (20 MW), West Gates solar station (10 MW), and Westside solar station (15 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

The Utility has applied to transfer its non-nuclear generation assets to Pacific Generation and potentially sell a minority interest in Pacific Generation. (For more information, see "Application with Pacific Generation LLC for Approval to Transfer Non-Nuclear Generation Assets" in Item 7. MD&A below.)

Generation Resources from Third Parties

The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. See "Ratemaking Mechanisms" above. For more information regarding the Utility's power purchase agreements, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

As of December 31, 2022, the Utility owned approximately 18,000 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 33 electric transmission substations with a capacity of approximately 65,000 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes many western states, the Canadian provinces of Alberta and British Columbia, and parts of Mexico.

Decisions about expansions and maintenance of the transmission system can be influenced by decisions of the Utility's regulators and the CAISO.

Electricity Distribution

The Utility's electric distribution network consists of approximately 108,000 circuit miles of distribution lines (of which, as of December 31, 2022, approximately 25% are underground and approximately 75% are overhead), 67 transmission switching substations, and 752 distribution substations with a capacity of approximately 36,000 MVA. The Utility's distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

These distribution substations serve as the central hubs for the Utility's electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. The Utility operates electric distribution control center facilities in Concord, Rocklin, and Fresno, California; these control centers form a key part of the Utility's efforts to create a smarter, more resilient grid.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2020 to 2022 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2022, 2021 or 2020.

	2022	2021	2020
Customers (average for the year)	5,562,223	5,539,969	5,498,044
Deliveries (in GWh) (1)	77,769	78,588	78,497
Revenues (in millions):			
Residential	$ 6,130	$ 6,089	$ 5,523
Commercial	5,416		

5,042

4,722

Industrial

1,626

1,493

1,530

Agricultural

1,830

1,565

1,471

Public street and highway lighting

77

73

69

Other, net

(2)

(247)

(84)

(130)

Subtotal

14,832

14,178

13,185

Regulatory balancing accounts

(3)

228

953

673

Total operating revenues

$

15,060

$

15,131

$

13,858

Selected Statistics:

Average annual residential usage (kWh)

5,564

5,889

6,179

Average billed revenues per kWh:

Residential

$

0.2253

$

0.2125

$

0.1852

Commercial

0.1896

0.1802

0.1730

Industrial

0.1177

0.1075

0.1085

Agricultural

0.2435

0.2104

0.2210

Net plant investment per customer

$

9,967

$

9,199

$

8,889

(1)

These amounts include electricity provided by DA providers and CCAs that procure their own supplies of electricity for their respective customers.

(2)

This activity is primarily related to the change in unbilled revenue and amounts subject to refund, partially offset by other miscellaneous revenue items.

(3)

These amounts represent revenues authorized to be billed.

Natural Gas Utility Operations

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service area. Core customers can purchase natural gas procurement service (i.e.

,

natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as "core transport agents"). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering, and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. More than 96% of core customers, representing approximately 85% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility generally does not provide procurement service to non-core customers, which must purchase their gas supplies from third-party suppliers, unless the customer is a natural gas-fired generation facility with which the Utility has a power purchase agreement that includes its generation fuel expense. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service area) and to third-party natural gas storage customers.

Natural Gas Supplies

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have varied generally based on market conditions. During 2022, the Utility purchased approximately 296,000 MMcf of natural gas (net of the sale of excess supply of gas).

Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 47% of the total natural gas volume the Utility purchased during 2022.

Natural Gas System Assets

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2022, the Utility's natural gas system consisted of approximately 44,000 miles of distribution pipelines, over 6,300 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one compressor station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for the transportation of natural gas from various natural gas supply points and interconnection points to the Utility's natural gas transportation system. These agreements provide transportation service from western Canada to the United States-Canada border, from the United States-Canada border to an interconnection point with the Utility's natural gas transportation system at the Oregon-California border, from the U.S. Rocky Mountains to an interconnection point with the Utility's natural gas transportation system at the Oregon-California border, and from supply points in the southwestern United States to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. (For more information regarding the Utility's natural gas transportation agreements, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's gas transmission system. In 2019, the CPUC approved the discontinuation, through closure or sale, of operations at two of the Utility's owned and operated gas storage fields, Pleasant Creek and Los Medanos. The Utility expects to sell Pleasant Creek in 2023 in accordance with the CPUC's final decision in the 2019 GT&S rate case. The Utility intends to retain the Los Medanos field to further support system supply reliability as proposed in the 2023 GRC. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later for withdrawal. In addition, four independent storage operators are interconnected to the Utility's Northern California gas transmission system.

In 2022, the Utility continued upgrading transmission pipeline to allow for the use of in-line inspection tools and substantially completed its work on the final recommendation from the NTSB's 2010-11 San Bruno investigation to confirm testing or perform a hydrostatic test for all Class 3 and Class 4 pipelines and all high consequence pipeline mileage.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2020 through 2022 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2022, 2021 or 2020.

2022

2021

2020

Customers (average for the year)

(1)

4,585,126

4,563,747

4,545,700

Gas purchased (MMcf)

227,128

226,037

226,746

Average price of natural gas purchased (price per Mcf)

$

7.42

$

3.19

$

2.02

Bundled gas sales (MMcf):

Residential

160,449

162,205

162,682

Commercial

57,066

54,262

49,834

Total Bundled Gas Sales

217,515

216,467

212,516

Revenues (in millions):

Bundled gas sales:

Residential

$

3,353

$

2,759

$

2,517

Commercial

1,005

713

597

Other

163

140

61

Bundled gas revenues

4,521

3,612

3,175

Transportation service only revenue

1,534

1,346

1,211

Subtotal

6,055

4,958

4,386

Regulatory balancing accounts

(2)

565

553

225

Total operating revenues

$

6,620

$

5,511

$

4,611

Selected Statistics:

Average annual residential usage (Mcf)

37

37

37

Average billed bundled gas sales revenues per Mcf:

Residential

$

20.22

$

16.54

$

15.09

Commercial

15.19

11.63

10.61

Net plant investment per customer

$

4,522

$

4,130

$

3,794

(1)

These amounts include natural gas provided by core transport agents and CCAs that procure their own supplies of natural gas for their respective customers.

(2)

These amounts represent revenues authorized to be billed.

Competition

Trends in Market Demand and Competitive Conditions in the Electricity Industry

The Utility expects customer electric load to increase in coming years primarily as a result of electrification of buildings and transportation. The Utility is not able to predict how quickly this electrification will occur. The Utility expects customer demand for gas to decrease in the coming years, primarily in response to policies supporting California's climate goals.

California law allows qualifying non-residential electric customers of IOUs to purchase electricity from energy service providers rather than from the utilities up to certain annual limits specified for each utility. This arrangement is known as DA. In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a CCA to generate or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses that do not affirmatively elect to continue to receive electricity generated or procured by a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to DA customers at the election of their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of DA and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last resort for these customers. Section 387 of the Public Utilities Code allows for a request to transfer the responsibilities of the provider of last resort obligation from IOUs to other entities.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and customer enrollment in NEM, which allows self-generating customers employing qualifying renewable resources to receive bill credits at the full retail rate, are increasing, putting upward rate pressure on remaining customers. New NEM customers, as well as customers interconnecting on the successor to the NEM tariffs, are required to pay an interconnection fee, utilize time of use rates, and are required to pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers or adopt self-generation technologies. See "Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE" in Item 1A. Risk Factors and "Regulatory Matters - OIR to Revisit Net Energy Metering Tariffs" in Item 7. MD&A.

Further, in some circumstances, governmental entities such as cities and irrigation districts may have authority under the state constitution or state statute to provide retail electric service directly to consumers. Those entities may rely upon FERC open access tariffs and Utility infrastructure to deliver energy to them at wholesale rates for resale at retail to existing or potential new Utility customers. These entities may also seek to acquire the Utility's transmission or distribution facilities through eminent domain for use in serving electricity at retail to existing or potential new Utility customers. As a result, the Utility could lose customers (residential, commercial, and industrial) in the municipality. See "Jurisdictions may attempt to acquire the Utility's assets through eminent domain" in Item 1A. Risk Factors. It is also expected that some publicly-owned utilities will build new or duplicate transmission or distribution facilities to serve existing or potential new Utility customers. In some instances, microgrid formation is a key factor in a community's choice to engage governmental entities.

The effect of such types of retail competition generally is to reduce the number of utility customers, leading to a reduction in the Utility's rate base.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service area through a competitive bidding process managed by the CAISO.

For risks in connection with increasing competition, see Item 1A. Risk Factors.

Competition in the Natural Gas Industry

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

Section: Item1a

>ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting estimates described in Item 7. MD&A,

that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with Item 7. MD&A and the Consolidated Financial Statements and related notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this 2022 Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risk Factors Summary

The following is a summary of the principal risks that could adversely affect our business, operations, and financial results. These risks are discussed more fully below.

Risks related to wildfires, including risks related to:

- The extent to which the Wildfire Fund and revised recoverability standard under AB 1054 effectively mitigate the risk of liability for damages arising from catastrophic wildfires;
- The 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, the 2022 Mosquito fire, or future wildfires;
- Recovery of excess costs in connection with wildfires; and

- Implementation of wildfire mitigation initiatives.

Risks related to operations and information technology, including risks related to:

- The hazardous nature of the Utility's electricity and natural gas operations;

-

Changes in the electric power and gas industries;

-

A cyber incident, cyber security breach, severe natural event or physical attack;

-

The operation and decommissioning of the Utility's nuclear generation facilities; and

-

Attracting and retaining specialty personnel.

Risks related to environmental factors, including risks related to:

-

Severe weather conditions, extended drought and climate change and events resulting from these conditions (including wildfires); and

-

Extensive environmental laws.

Risks related to enforcement matters, investigations, and regulatory proceedings, including risks related to:

-

The Enhanced Oversight and Enforcement Process;

-

Legislative and regulatory developments;

-

Outcomes of enforcement proceedings in connection with extensive regulations to which the Utility is subject; and

-

Outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its costs.

Risks related to financial conditions, including risks related to:

-

PG&E Corporation's and the Utility's substantial indebtedness;

-

Restrictions in indebtedness documents;

-

Appeals of the Confirmation Order;

-

Potential additional dilution to holders of PG&E Corporation common stock;

-

Any substantial sale of stock by existing stockholders;

-

Ownership and transfer restrictions associated with PG&E Corporation common stock;

-

Tax-related risks and uncertainties, including the grantor trust election for the Fire Victim Trust;

-

The inability of PG&E Corporation to use some or all of its net operating loss carryforwards and other tax attributes to offset future income;

-

Restrictions on PG&E Corporation's and the Utility's ability to issue dividends;

-

PG&E Corporation's reliance on dividends, distributions and other payments from the Utility;

-

Restrictions on shareholders

'

ability to change the direction or management of PG&E Corporation;

-

The COVID-19 pandemic;

- Increased customer rates; and
- Inflation.

Risks Related to Wildfires

The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires.

If the Utility does not have an approved WMP, the Utility will not be issued a safety certification and will consequently not benefit from the presumption of prudency or the AB 1054 disallowance cap. Under AB 1054, the Utility is required to maintain a safety certification issued by the OEIS to be eligible for certain benefits, including a cap on Wildfire Fund reimbursement and a reformed prudent manager standard. The AB 1054 Wildfire Fund disallowance cap, which caps the amount of liability that the Utility could be required to bear for a catastrophic wildfire, is inapplicable 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 at the time the applicable wildfire ignited. In addition, if the Utility fails to maintain a valid safety certification at the time a wildfire ignites, the initial burden of proof in a prudency proceeding shifts from intervenors to the Utility. The Utility will be required to reimburse amounts that are determined by the CPUC not to be just and reasonable. For more information on the disallowance cap, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Furthermore, 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. If the Utility is unable to maintain an AB 1054 safety certification or if the Wildfire Fund is exhausted, the inability to access the Wildfire Fund could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Also, 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.

The costs of participating in the Wildfire Fund are expected to exceed $6.7 billion over the anticipated ten-year contribution period for the fund. The timing and amount of any potential charges associated with the Utility's contributions would also depend on various factors. In addition, there could also be a significant delay between the occurrence of a wildfire and the timing on which the Utility recognizes impairment for the reduction in future coverage, due to the lack of data available to the Utility following a catastrophic event, especially if the wildfire occurs in the service area of another participating electric utility. Participation in the Wildfire Fund is expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, and there can be no assurance that the benefits of participating in the Wildfire Fund ultimately outweigh these substantial costs.

PG&E Corporation and the Utility could be liable as a result of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, the 2022 Mosquito 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 losses in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire. Although PG&E Corporation and the Utility have recorded liabilities for probable losses in connection with these fires, 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.

Although there are a number of unknown facts surrounding Cal Fire's causation determinations of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire, the Utility could be subject to significant liability in excess of recoveries 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 document, data, and other information requests from the CPUC's SED, the DOJ, and law enforcement agencies that are investigating these wildfires. 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, the 2022 Mosquito fire, or other wildfires. For more information, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Criminal charges have been filed against the Utility in connection with the 2020 Zogg fire. Under California law (including Penal Code section 1202.4), if the Utility were convicted of any of the charges, 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 victims and is not offset by any compensation that the victims have received or may receive from their insurance carriers. If convicted of any of the charges, the Utility currently believes that its total losses associated with the 2020 Zogg fire could materially exceed the accrued estimated liabilities that PG&E Corporation and the Utility have recorded to reflect the lower end of the range of the reasonably estimable range of losses. The Utility is 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.

There have been numerous other wildfires in the Utility's service area, of which the Utility has not been alleged or determined to be a cause. The Utility could be alleged or determined to be a cause of one or more of these wildfires.

Additionally, under the doctrine of inverse condemnation, courts have imposed liability 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, even if the utility is unable to recover these costs through rates. In fact, in December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it had incurred as a result of the doctrine of inverse condemnation. Legal challenges to that denial were unsuccessful. Plaintiffs have asserted and continue to assert the doctrine of inverse condemnation in lawsuits related to certain wildfires that occurred in the Utility's service area. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities' electric transmission lines. While the Utility continues to dispute the applicability of inverse condemnation to the Utility, there can be no assurance that the Utility will be successful in challenging the applicability of inverse condemnation in the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, the 2022 Mosquito fire, or other litigation against PG&E Corporation or the Utility.

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. Once an ignition has occurred, the Utility is unable to control the extent of damages. The extent of damages for a wildfire is primarily determined by environmental conditions (including weather and vegetation conditions), third-party suppression efforts, and the location of the wildfire.

In addition, wildfires have had and could continue to have (as a result of any future wildfires) adverse consequences on the Utility's proceedings with the CPUC (including the Safety Culture OII) and the FERC, and future regulatory proceedings, including future applications with the OEIS 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, the 2020 Zogg fire, the 2021 Dixie fire, the 2022 Mosquito fire, or any future wildfires. For more information about the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility may be unable to recover all or a significant portion of its costs in excess of insurance coverage in connection with wildfires, through rates, or from the Wildfire Fund in a timely manner.

The Utility could incur substantial costs in excess of insurance coverage or amounts potentially available under the Wildfire Fund under AB 1054 in the future in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire. There can be no assurance that the Utility will be allowed to recover costs in excess of insurance or amounts potentially available under the Wildfire Fund under AB 1054 in the future either through FERC TO rates or as costs recorded to the WEMA, 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. The inability to recover all or a significant portion of costs in excess of insurance through rates or by collecting such rates in a timely manner could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. For more information on wildfire recovery risk, see "The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires" above and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility may not effectively implement its wildfire mitigation initiatives.

The Utility's infrastructure is aging and poses risks to safety and system reliability. Although the Utility spends significant resources on initiatives designed to mitigate wildfire risks, there is no assurance that these initiatives will be successful or effective in reducing wildfire-related losses. The Utility will face a higher likelihood of catastrophic wildfires in its service area if it cannot effectively implement these efforts and its WMPs. For example, the Utility may not be able to effectively implement its WMPs if it experiences unanticipated difficulties relative to sourcing, engaging, training, overseeing, and retaining contract workers it needs to fulfill its mitigation obligations under the WMPs. The CPUC will assess penalties on the Utility if there is a finding that the Utility has failed to substantially comply with its WMPs.

There can be no assurance that the Utility's wildfire mitigation initiatives will be effective. For instance, a wildfire may be ignited and spread even in conditions that do not trigger proactive de-energization according to criteria for initiating a PSPS event or where EPSS has been implemented on Utility equipment. The Utility's inspections of vegetation near its assets may not detect structural weaknesses within a tree or other issues. If the Utility's wildfire mitigation initiatives are not effective, a wildfire could be ignited and spread.

The PSPS program has been subject to significant scrutiny and criticism by various stakeholders, including customers, regulators, and lawmakers. The Utility also is the subject of a class action litigation in connection with the 2019 PSPS events.

In addition, on a risk-informed basis, the Utility is making efforts to reduce the frequency and impacts of PSPS. The Utility may be subject to mandated changes to, or restrictions on, its operational practices, regulatory fines and penalties, claims for damages, and reputational harm if the Utility does not execute PSPS in compliance with applicable rules and regulations. The Utility establishes the criteria under which it implements PSPS in its territory. To the extent the Utility's criteria for implementing PSPS are not sufficient to mitigate the risk of wildfires, the Utility does not fully implement PSPS when criteria are met due to other overriding conditions or the Utility's regulators mandate changes to, or restrictions on, its criteria or other operational PSPS practices, the Utility will face a higher likelihood of catastrophic wildfires in its territory during high-risk weather conditions.

PG&E Corporation and the Utility cannot predict the timing and outcome of the various proceedings and litigation in connection with its wildfire mitigation initiatives. PG&E Corporation and the Utility could be subject to additional investigations, regulatory proceedings, or other enforcement actions as well as to additional litigation and claims by customers as a result of the Utility's implementation of its wildfire mitigation initiatives, which could result in fines, penalties, customer rebates, other payments, or the Utility's failure to obtain cost recovery for amounts expended on these initiatives. The amount of any fines, penalties, customer rebates or other payments (if PG&E Corporation or the Utility were to issue any credits, rebates or other payments in connection with any other wildfire mitigation initiatives or liability for damages) 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 PSPS and EPSS programs have had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers and future PSPS events and EPSS outages may increase these negative perceptions. For more information, see "Regulatory Matters" in Item 7. MD&A.

Risks Related to Operations and Information Technology

The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks.

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. above. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives. For more information, see "The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements or operating conditions change or the facilities cease operations before the licenses expire" below.

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

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the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines or other assets or group of assets, that can cause explosions, fires, public or workforce safety issues, large scale system disruption or other catastrophic events;

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- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled or uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees, contractors, or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wildfire or natural gas explosion);

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inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;

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operator or other human error;

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a motor vehicle or aviation incident involving a Utility vehicle or aircraft, respectively (or one operated on behalf of the Utility) resulting in serious injuries to or fatalities of the workforce or the public, property damage, or other consequences;

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an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;

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construction performed by third parties that damages the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines, the risk of which may be exacerbated if the Utility does not have an effective contract management system;

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the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and

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attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war. For more information, see "The Utility's operational networks and information technology systems could be impacted by a cyber incident, cyber security breach, severe natural event or physical attack" below.

The occurrence of any of these events could interrupt fuel supplies, affect demand for electricity or natural gas, cause unplanned outages or reduce generating output, damage the Utility's assets or operations, damage the assets or operations of third parties on which the Utility relies, damage property owned by customers or others, and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties. Any such incidents also could lead to significant claims against the Utility. Further, the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities, vegetation management, or the construction or demolition or facilities, and the Utility may have less control over contractors than its employees. The Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions or inactions.

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

The electric power and gas industries are undergoing significant changes driven by technological advancements and a decarbonized economy.

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice and state climate policy supporting a decarbonized economy. California utilities also are experiencing increasing deployment by customers and third parties of distributed energy resources, such as on-site solar generation, electric vehicles, energy storage, fuel cells, energy efficiency, and demand response technologies. These developments will require sustained investments in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, electric vehicle infrastructure and state infrastructure modernization (e.g., rail and water projects). The Utility may be unable to effectively adapt to these potential business and regulatory changes, for instance by failing to meet customer demand for new business interconnections in a timely manner. The CPUC is also conducting proceedings to evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of distributed energy resources and consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by distributed energy resources, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator. If the Utility is unable to effectively adapt to these potential business and regulatory changes its business model and its ability to execute on its strategy could be materially impacted.

Various jurisdictions within California have enacted prohibitions or restrictions on use and consumption of natural gas, for example in buildings, that will reduce the use of natural gas. Reducing natural gas use could lead to a reduction in the gas customer base and a diminished need for gas infrastructure and, as a result, could lead to certain gas assets no longer being "used and useful," potentially causing substantial investment value of gas assets to be stranded (under CPUC precedent, when an asset no longer meets the standard of "used and useful," the asset is removed from rate base, which results in a reduction in associated rate recovery). However, while natural gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing, among other things, to cover the cost of long-term pipeline safety enhancements. Inability by the Utility to recover through rates its investments into the natural gas system while still ensuring gas system safety and reliability could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

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

The Utility's operational networks and information technology systems could be impacted by a cyber incident, cyber security breach, severe natural event, or physical attack.

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

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

The Utility and its third-party vendors have been subject to, and will likely continue to be subject to, breaches and attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these breaches or attempts has individually or in the aggregate resulted in a security incident with a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in material fines and penalties, loss of customers and harm to PG&E Corporation's and the Utility's reputation, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no assurance that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable through rates.

The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities, and the Utility may not be able to fully recover its costs if regulatory requirements or operating conditions change or the facilities cease operations before the licenses expire.

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health, and financial risks, such as risks relating to operation of the Diablo Canyon nuclear generation units as well as the storage, handling, and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance coverage available, such losses could have a material effect on

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the Utility may be required under federal law to pay up to $275 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States.

The Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before their respective current licenses expire in 2024 and 2025 or prior to the expiration of any renewed license and extended operations period. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

If Diablo Canyon is retired by 2025, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employee retention program to ensure adequate staffing levels at Diablo Canyon, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the Utility. There can be no assurance that the Utility will be successful in retaining highly skilled personnel under its employee programs.

The Utility is pursuing the extension of operations at Diablo Canyon through no later than 2030. If Diablo Canyon enters extended operations, the Utility will face operational challenges resulting from a shortened planning period. For instance, the Utility may be unable to procure an adequate supply of nuclear fuel. For more information, see "Extension of Diablo Canyon Operations" under "Legislative and Regulatory Initiatives" in Item 7. MD&A.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. See "Regulatory Environment" in Item 1. Business above. If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon's two nuclear generation units before their respective current licenses expire in 2024 and 2025. As of December 31, 2022, the Utility's unrecovered investment in Diablo Canyon was $840 million.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. See "Asset Retirement Obligations" in Note 3 of the Notes to the Consolidated Financial Statement in Item 8. The Utility's costs to decommission its nuclear facilities through nuclear decommissioning are subject to reasonableness review by the CPUC. The Utility will be responsible for any costs that the CPUC determines were not reasonably incurred. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The Utility may be unable to attract and retain specialty personnel.

The Utility's workforce is aging, and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel in certain specialty operational positions.

Additionally, the Utility could experience labor disruptions from personnel in those positions. If the Utility were to experience such a shortage or disruptions, work stoppages could occur.

Any such occurrences could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risks Related to Environmental Factors

Severe weather conditions, extended drought, and climate change could materially affect PG&E Corporation and the Utility.

Extreme weather, drought and shifting climate patterns have intensified the challenges associated with many of the other risks facing PG&E Corporation and the Utility, particularly wildfire management in California. The Utility's service area 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 recent wildfire seasons, 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. As of December 31, 2022, more than 81% of California is experiencing severe to extreme drought. Moderate or severe drought conditions occur and can persist in virtually all of the Utility's service area. More than half of the Utility's service area is in an HFTD. 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. In January 2018, the CPUC approved a statewide fire-threat map that shows that approximately half of the Utility's service area is facing "elevated" or "extreme" fire danger. Approximately 25,000 circuit miles of the Utility's nearly 80,000 distribution overhead circuit miles and approximately 5,500 miles of the nearly 18,000 transmission overhead circuit miles are in such HFTDs, significantly more in total than other

California IOUs.

Severe weather events and other natural disasters, including wildfires and other fires, storms, tornadoes, floods, extreme heat events, drought, earthquakes, lightning, tsunamis, rising sea levels, pandemics, solar events, electromagnetic events, wind events or other weather-related conditions, climate change, or natural disasters, could result in severe business disruptions, prolonged power outages, property damage, injuries and loss of life, significant decreases in revenues and earnings, and 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 such event 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 or the failure of electric and other equipment of the Utility.

Further, the Utility has been studying the potential effects of climate change (increased severity and frequency of storm events, sea level rise, land subsidence, change in temperature extremes, changes in precipitation patterns and drought, and wildfire) on its assets, operations, and services, and the Utility is developing adaptation plans to set forth a strategy for those events and conditions that the Utility believes are most significant. Consequences of these climate-driven events may vary widely and could include increased stress on the energy supply network due to new patterns of demand, reduced hydroelectric output, physical damage to the Utility's infrastructure, higher operational costs, and an increase in the number and duration of customer outages and safety consequences for both employees and customers. 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, windstorms, 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. See "Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE" below.

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

The Utility's operations are subject to extensive environmental laws, and such laws could change.

The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. For more information, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, or stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future, or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover through rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. See "Environmental Regulation" in Item 1. and Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination, changes in estimated costs, and the extent to which actual remediation costs differ from recorded liabilities have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risks Related to Other Enforcement Matters, Investigations, and Regulatory Proceedings

PG&E Corporation and the Utility are subject to the Enhanced Oversight and Enforcement Process.

The EOEP is a six-step process with potentially escalating CPUC oversight and enforcement measures based on specific "triggering events" identified for each of the six steps. If the Utility is placed into the EOEP, it will be subject to additional reporting requirements and additional monitoring and oversight by the CPUC. Higher steps of the process (steps 3 through 6) also contemplate additional enforcement mechanisms, including appointment of an independent third-party monitor, appointment of a chief restructuring officer, pursuit of the receivership remedy, and review of the Utility's Certificate of Public Convenience and Necessity (i.e., its license to operate as a utility). The process contains provisions for the Utility to cure and exit the process if it can satisfy specific criteria. The EOEP states that the Utility should presumptively move through the steps of the process sequentially, but the CPUC may place the Utility into the appropriate step of the process upon occurrence of a specified triggering event.

PG&E Corporation and the Utility could be materially affected by legislative and regulatory developments.

The Utility and its operations are subject to extensive federal, state, and local laws, regulations, and orders. The Utility incurs significant capital, operating, and other costs associated with compliance with these rules. These rules could change, which could change the Utility's compliance obligations and the costs to comply with these rules. Non-compliance with these rules could result in the imposition of material fines on PG&E Corporation and the Utility, other regulatory exposure, significant litigation, and reputational harm, which could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Wildfire

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Wildfire Fund does not effectively mitigate the financial risk of liability for damages arising from catastrophic wildfires where the Utility's facilities are a substantial cause. See "The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires." above.

Privacy

In June 2018, the State of California enacted the CCPA, which went into effect on January 1, 2020, with a 12-month look-back period requiring compliance by January 1, 2019. The State of California announced enacted regulations in August 2020 and March 2021 which provide guidance on the requirements of the CCPA. The CCPA requires companies that process information on California residents to make new disclosures to consumers about their data collection, use and sharing practices, allows consumers to opt out of certain data sharing with third parties and provides a new cause of action for data breaches. The CCPA provides for financial penalties in the event of non-compliance and statutory damages in the event of a data security breach. On November 3, 2020, Californians voted to approve Proposition 24, a ballot measure that creates the California Privacy Rights Act (the "CPRA"), which amended and expanded the CCPA. The State of California enacted the CPRA in November 2020, with most provisions operative as of January 1, 2023 and applicable to personal information collected beginning January 1, 2022. Final CPRA regulations are in development. Failure to comply with the CCPA and the CPRA could result in litigation, audits, and the imposition of material fines on PG&E Corporation and the Utility.

Additionally, PG&E Corporation and the Utility collect and retain certain personal information of their customers, shareholders, and employees in connection with their business. Although PG&E Corporation and the Utility invest in risk management and information security measures, the personal information that they collect, as well as other commercially-sensitive data that they possess, could become compromised because of certain events, including a cyber incident, the insufficiency or failure of such measures, human error, the misappropriation of data, or the occurrence of any of the foregoing at any third party with which PG&E Corporation or the Utility has shared information. If any of these events were to transpire, it could subject PG&E Corporation and the Utility to financial liability.

PG&E Corporation and the Utility are subject to federal and state privacy laws, which grant consumers rights and protections, including, among other things, the ability to opt out of receiving certain communications and certain data sharing with third parties.

Environmental

The environmental rules to which the Utility's operations are subject relate to air quality, water quality and usage, remediation of hazardous substances, and the protection and conservation of natural resources and wildlife.

Also, SB 100 (the 100 Percent Clean Energy Act of 2018) increased the percentage from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and established state policy that 100% of all retail electricity sales must come from renewable portfolio standard-eligible or carbon-free resources by 2045. Failure to comply with SB 100 could result in fines imposed on PG&E Corporation and the Utility that could be material.

The Utility is subject to extensive regulations and the risk of enforcement proceedings in connection with compliance with such regulations.

The Utility is subject to extensive regulations, including federal, state, and local energy, environmental and other laws and regulations, and the risk of enforcement proceedings in connection with compliance with such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the Safety Culture OII (as defined in "Order Instituting an Investigation into PG&E Corporation's and the Utility's Safety Culture" under "Regulatory Matters" in Item 7. MD&A) and other matters that the CPUC's SED may be investigating. The SED could launch investigations at any time on any issue it deems appropriate. In addition, OEIS has authority to approve and oversee compliance with the WMP and may determine that the Utility has failed to substantially comply with its WMP.

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state, or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and RA requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC GOs or other applicable CPUC decisions or regulations; whether the Utility is able to achieve the targets in its WMPs; federal electric reliability standards; and environmental compliance. CPUC staff could also impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds depends on a variety of factors and could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility also is a target of a number of investigations, in addition to certain investigations in connection with the wildfires. See "Risks Related to Wildfires" above. The Utility is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility, or the amount of any costs and expenses associated with such investigations.

If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties, the amount of which could be substantial, and, in the event of a judgment against the Utility, suffer further ongoing negative consequences. Furthermore, a negative outcome in any of these investigations, or future enforcement actions, could negatively affect the outcome of future ratemaking and regulatory proceedings to which the Utility may be subject; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations.

The Utility's ratemaking and cost recovery proceedings may not authorize sufficient revenues, or the Utility's actual costs could exceed its authorized or forecasted costs due to various factors, including if the Utility is not able to manage its costs effectively.

The Utility's financial results depend on its ability to earn a reasonable return on capital, including long-term debt and equity, and to recover costs from its customers, through the rates it charges its customers as approved by the CPUC and the FERC. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility or if the amount of actual costs incurred differs from the forecast or authorized costs embedded in rates. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services. If the CPUC does not authorize sufficient funding for investments in the Utility's infrastructure, it may negatively impact the Utility's ability to modernize the grid and make it resilient to risks related to climate change, including wildfires.

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility's actual costs differ from authorized or forecast costs. The Utility's ability to recover its costs and earn a reasonable rate of return can be affected by many factors, including the time delay between when costs are incurred and when those costs are recovered through rates. The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. Further, the Utility may be required to incur expenses before the relevant regulatory agency approves the recovery of such costs. For example, the Utility has incurred, and continues to incur, costs to strengthen its wildfire mitigation and prevention efforts before it is clear whether such costs will be recoverable through rates. Also, the CPUC may deny recovery of uninsured wildfire-related costs incurred by the Utility if the CPUC determines that the Utility was not prudent.

The Utility may incur additional costs or receive reduced revenue for many reasons including changing market circumstances, unanticipated events (such as wildfires, storms, earthquakes, accidents, or catastrophic or other events affecting the Utility's operations), increased self-generation by customers, an increase in distributed generation, lower customer demand due to adverse economic conditions, the loss of the Utility's customers to other retail providers like CCAs or DA providers, whether the CAISO wholesale electricity market continues to function effectively, returning customers, or compliance with new state laws or policies. See "Trends in Market Demand and Competitive Conditions in the Electricity Industry" in Item 1.

Jurisdictions may attempt to acquire the Utility's assets through eminent domain.

Jurisdictions may attempt to acquire the Utility's assets through eminent domain ("municipalization"). In particular, the City and County of San Francisco ("San Francisco") has submitted a petition with the CPUC seeking a valuation of the Utility's electric assets in San Francisco and has expressed intent to acquire such assets. While San Francisco would still need to, among other things, initiate and prevail in an eminent domain action in state court to acquire the Utility's assets, there is no guarantee that the Utility would be successful in defending against such an action or related regulatory proceeding. If municipalization proceedings are permitted to move forward and are successful, the Utility would be entitled to receive the fair market value of the assets that are subject to the takeover effort, but the valuation issues in any municipalization proceeding would be highly contentious and could result in the Utility receiving less than what it believes is just compensation for the applicable assets. Any assets acquired by a third party through eminent domain would be excluded from the Utility's rate base, reducing the Utility's revenues and opportunity to earn a return on such assets. Assets that are targeted for municipalization generally are located in geographic areas that have a lower cost of service relative to billed revenues, so municipalization could negatively impact the affordability of the Utility's service for remaining Utility customers served outside of those geographic areas. A successful municipalization attempt could also encourage similar attempts by other municipalities which, if successful, would further divide the Utility's assets and reduce the Utility's rate base, profitability, and affordability for remaining Utility customers. It is also unclear how the CPUC would allocate the compensation received by the Utility for its assets between shareholders and customers. As a result of these factors, municipalization could materially affect the Utility's financial condition, results of operations, liquidity, and cash flow.

Risks Related to PG&E Corporation's and the Utility's Environment and Financial Condition

PG&E Corporation's and the Utility's substantial indebtedness may adversely affect their financial health and operating flexibility.

PG&E Corporation and the Utility have a substantial amount of indebtedness, most of which is secured by liens on certain assets of PG&E Corporation and the Utility. As of December 31, 2022, PG&E Corporation had approximately $4.68 billion of outstanding indebtedness (such indebtedness consisting of PG&E Corporation's $1.0 billion aggregate principal amount of senior secured notes due 2028, $1.0 billion aggregate principal amount of senior secured notes due 2030, and borrowings under the $2.75 billion secured term loan agreement entered into in June 2020), and the Utility had approximately $45.6 billion of outstanding indebtedness. In addition, PG&E Corporation had $500 million of additional borrowing capacity under the Corporation Revolving Credit Agreement, and the Utility had $1.5 billion of additional borrowing capacity under the Utility Revolving Credit Agreement. In addition, the Utility had outstanding preferred stock with an aggregate liquidation preference of $252 million.

Since PG&E Corporation and the Utility have a high level of debt, a substantial portion of cash flow from operations will be used to make payments on this debt. Furthermore, since a significant percentage of the Utility's assets are used to secure its debt, this reduces the amount of collateral available for future secured debt or credit support and reduces its flexibility in operating these secured assets. This relatively high level of debt and related security could have other important consequences for PG&E Corporation and the Utility, including:

- limiting their ability or increasing the costs to refinance their indebtedness;

- limiting their ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of their business strategy or other purposes;

- limiting their ability to use operating cash flow in other areas of their business;

- increasing their vulnerability to general adverse economic and industry conditions, including increases in interest rates, particularly given their substantial indebtedness that bears interest at variable rates, as well as to catastrophic events; and

- limiting their ability to capitalize on business opportunities.

Under the terms of the agreements and indentures governing their respective indebtedness, PG&E Corporation and the Utility are permitted to incur additional indebtedness, some of which could be secured (subject to compliance with certain tests) and which could further accentuate these risks.

As a result of the high level of indebtedness, PG&E Corporation and the Utility may be unable to generate sufficient cash through operations to service such debt, and may need to refinance such indebtedness at or prior to maturity and be unable to obtain financing on suitable terms or at all. As a capital-intensive company, the Utility relies on access to the capital markets. If the Utility were unable to access the capital markets or the cost of financing were to substantially increase, its financial condition, results of operations, liquidity, and cash flows could be materially affected. The Utility's ability to obtain financing, as well as its ability to refinance debt and make scheduled payments of principal and interest, are dependent on numerous factors, including the Utility's levels of indebtedness, maintenance of acceptable credit ratings, financial performance, liquidity and cash flow, and other market conditions. The Utility's inability to service its substantial debt or access the financial markets on reasonable terms could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The documents that govern PG&E Corporation's and the Utility's indebtedness limit their flexibility in operating their business.

PG&E Corporation's and the Utility's material financing agreements, including certain of their respective credit agreements and indentures, contain various covenants restricting, among other things, their ability to:

- incur or assume indebtedness or guarantees of indebtedness;
- incur or assume liens;
- sell or dispose of all or substantially all of its property or business;
- merge or consolidate with other companies;
- enter into any sale leaseback transactions; and
- enter into swap agreements.

The restrictions contained in these material financing agreements could affect PG&E Corporation's and the Utility's ability to operate their business and may limit their ability to react to market conditions or take advantage of potential business opportunities as they arise. For example, such restrictions could adversely affect PG&E Corporation's and the Utility's ability to finance their operations and expenditures, make strategic acquisitions, investments, or alliances, sell assets, restructure their organization, or finance their capital needs. Additionally, PG&E Corporation's and the Utility's ability to comply with these covenants and restrictions may be affected by events beyond their control, including prevailing regulatory, economic, financial and industry conditions.

Parties have appealed the Confirmation Order.

Following entry of the Confirmation Order confirming the Plan, certain parties filed notices of appeal with respect to the Confirmation Order. While a number of such appeals have been dismissed, there can be no assurance that any of the remaining appeals 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. See Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

PG&E Corporation may be required to issue shares with respect to HoldCo Rescission or Damage Claims, which would result in dilution to holders of PG&E Corporation common stock, or pay a material amount of cash with respect to allowed Subordinated Debt Claims.

On the Emergence Date, PG&E Corporation issued to the Fire Victim Trust a number of shares of common stock equal to 22.19% of the outstanding common stock on such date. As further described in "Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8, PG&E Corporation may be required to issue shares of its common stock in satisfaction of allowed HoldCo Rescission or Damage Claims. If such issuance is required, it may be determined that, under the Plan, the Fire Victim Trust should receive additional shares of PG&E Corporation common stock such that it would have owned 22.19% of the outstanding common stock of reorganized PG&E Corporation on the Emergence Date, assuming that such issuance of shares in satisfaction of the HoldCo Rescission or Damage Claims had occurred on the Emergence Date. Any such issuances will result in dilution to anyone who holds shares of PG&E Corporation common stock prior to such issuance and may cause the trading price of PG&E Corporation shares to decline.

Additionally, PG&E Corporation may be required to pay a material amount of cash with respect to allowed Subordinated Debt Claims (as defined in "Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims" in Note 15 of the Notes to the Consolidated Financial

Statements in Item 8). Such payment may have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Any substantial sale of stock by existing stockholders could depress the market value of PG&E Corporation's common stock, thereby devaluing the market price.

Certain stockholders, including the Fire Victim Trust, received a large number of shares in the Chapter 11 Cases and may continue to hold shares of PG&E Corporation. PG&E Corporation can make no prediction as to the effect, if any, that sales of shares, or the availability of shares for future sale, will have on the prevailing market price of shares of PG&E Corporation common stock. Sales of substantial amounts of shares of common stock in the public market, or the perception that such sales could occur, could depress prevailing market prices for such shares. Such sales may also make it more difficult for PG&E Corporation to sell equity securities or equity-linked securities in the future at a time and price which it deems appropriate.

PG&E Corporation may also sell additional shares of common stock in subsequent offerings or issue additional shares of common stock or securities convertible into shares of PG&E Corporation common stock. The issuance of any shares of PG&E Corporation common stock in future financings, acquisitions upon conversion or exercise of convertible securities, or otherwise may result in a reduction of the book value and market price of PG&E Corporation's outstanding common stock. If PG&E Corporation issues any such additional shares, the issuance will cause a reduction in the proportionate ownership and voting power of all current shareholders. PG&E Corporation cannot predict the size of future issuances of shares of PG&E Corporation common stock or securities convertible into shares of PG&E Corporation common stock or, for any issuance, the effect, if any, that such future issuances will have on the market price of PG&E Corporation's common stock.

PG&E Corporation common stock is subject to ownership and transfer restrictions intended to preserve PG&E Corporation's ability to use its net operating loss carryforwards and other tax attributes.

PG&E Corporation has incurred and may also continue to incur, in connection with the Plan, significant net operating loss carryforwards and other tax attributes, the amount and availability of which are subject to certain qualifications, limitations and uncertainties. The Amended Articles (as defined below) impose certain restrictions on the transferability and ownership of PG&E Corporation common stock and preferred stock (together, the "capital stock") and other interests designated as "stock" of PG&E Corporation by the Board of Directors as disclosed in an SEC filing (such stock and other interests, the "Equity Securities," and such restrictions on transferability and ownership, the "Ownership Restrictions") in order to reduce the possibility of an equity ownership shift that could result in limitations on PG&E Corporation's ability to utilize net operating loss carryforwards and other tax attributes from prior taxable years or periods for federal income tax purposes. Any acquisition of PG&E Corporation capital stock that results in a shareholder being in violation of these restrictions may not be valid.

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Subject to certain exceptions, the Ownership Restrictions restrict (i) any person or entity (including certain groups of persons) from directly or indirectly acquiring or accumulating 4.75% or more of the outstanding Equity Securities and (ii) the ability of any person or entity (including certain groups of persons) already owning, directly or indirectly, 4.75% or more of the Equity Securities to increase their proportionate interest in the Equity Securities. For more information, see "Because PG&E Corporation and the Utility have elected 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" below. Any transferee receiving Equity Securities that would result in a violation of the Ownership Restrictions will not be recognized as a shareholder of PG&E Corporation or entitled to any rights of shareholders, including, without limitation, the right to vote and to receive dividends or distributions, whether liquidating or otherwise, in each case, with respect to the Equity Securities causing the violation.

The Ownership Restrictions remain in effect until the earliest of (i) the repeal, amendment, or modification of Section 382 (and any comparable successor provision) of the IRC, in a manner that renders the restrictions imposed by Section 382 of the IRC no longer applicable to PG&E Corporation, (ii) the beginning of a taxable year in which the Board of Directors of PG&E Corporation determines that no tax benefits attributable to net operating losses or other tax attributes are available, (iii) the date selected by the Board of Directors if it determines that the limitation amount imposed by Section 382 of the IRC as of such date in the event of an "ownership change" of PG&E Corporation (as defined in Section 382 of the IRC and Treasury Regulation Sections 1.1502-91 et seq.) would not be materially less than the net operating loss carryforwards or "net unrealized built-in loss" (within the meaning of Section 382 of the IRC and Treasury Regulation Sections 1.1502-91 et seq.) of PG&E Corporation, and (iv) the date selected by the Board of Directors if it determines that it is in the best interests of PG&E Corporation's shareholders for the Ownership Restrictions to be removed or released. The Ownership Restrictions may also be waived by the Board of Directors on a case by case basis.

Because PG&E Corporation and the Utility have elected 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.

On July 8, 2021, PG&E Corporation, the Utility, ShareCo, and the Fire Victim Trust entered into the Share Exchange and Tax Matters Agreement, pursuant to which PG&E Corporation and the Utility made a grantor trust election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

As a result of the grantor trust election, shares of PG&E Corporation common stock owned by the Fire Victim Trust are treated as held by the Utility and, in turn attributed to PG&E Corporation for income tax purposes. Consequently, 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 Stock Ownership (as defined in the Amended Articles) for purposes of the Ownership Restrictions. See "Tax Matters" in Item 7. MD&A for an example of these calculations. 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, the Utility, and ShareCo 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 (calculated as excluding any shares owned by the Fire Victim Trust, the Utility, and ShareCo from the number of outstanding equity securities). All current and prospective shareholders are advised to consider the foregoing in determining their ownership and acquisition of PG&E Corporation common stock.

PG&E Corporation may not be able to use some or all of its net operating loss carryforwards and other tax attributes to
offset future income.

As of December 31, 2022, PG&E Corporation had net operating loss carryforwards for PG&E Corporation's consolidated group for U.S. federal and California income tax purposes of approximately $26.6 billion and $25.2 billion, respectively, and PG&E Corporation incurred and may also continue to incur, in connection with the Plan, significant net operating loss carryforwards and other tax attributes. The ability of PG&E Corporation to use some or all of these net operating loss carryforwards and certain other tax attributes may be subject to certain limitations. Under Section 382 of the IRC (which also applies for California state income tax purposes), if a corporation (or a consolidated group) undergoes an "ownership change," such 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).

As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change and its net operating loss carryforwards and other tax attributes are not limited by Section 382 of the IRC. However, whether PG&E Corporation underwent or will undergo an ownership change as a result of the transactions in PG&E Corporation's equity that occurred pursuant to the Plan depends on several factors outside PG&E Corporation's control and the application of certain laws that are uncertain in several respects. Accordingly, there can be no assurance that the Internal Revenue Service would not successfully assert that PG&E Corporation has undergone or will undergo an ownership change pursuant to the Plan. In addition, even if these transactions did not cause an ownership change, they may increase the likelihood that PG&E Corporation may undergo an ownership change in the future. If the Internal Revenue Service successfully asserts that PG&E Corporation did undergo, or PG&E Corporation otherwise does undergo, an ownership change, the limitation on its net operating loss carryforwards and other tax attributes under Section 382 of the IRC could be material to PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

In particular, limitations imposed on PG&E Corporation's ability to utilize net operating loss carryforwards or other tax attributes could cause U.S. federal and California income taxes to be paid earlier than would be paid if such limitations were not in effect and could cause such net operating loss carryforwards or other tax attributes to expire unused, in each case reducing or eliminating the benefit of such net operating loss carryforwards and other tax attributes. In addition, PG&E Corporation's ability to utilize its net operating loss carryforwards to fund a customer credit trust is critical to whether the impact of the fixed recovery charges paid by customers pursuant to the SB 901 securitization transactions will be neutral, on average, to such customers. Further, PG&E Corporation's ability to utilize its net operating loss carryforwards is critical to PG&E Corporation's and the Utility's commitment to make certain operating and capital expenditures. Failure to obtain alternative sources of capital could have a material adverse effect on PG&E Corporation and the Utility and the value of PG&E Corporation common stock.

PG&E Corporation's ability to pay dividends on shares of its common stock is subject to restrictions.

Pursuant to the Confirmation Order, PG&E Corporation may not pay dividends on shares of its common stock until it recognizes $6.2 billion in Non-GAAP Core Earnings following the Emergence Date. "Non-GAAP Core Earnings" means GAAP earnings adjusted for certain non-core items as described in the Plan.

Subject to the foregoing restrictions, any decision to declare and pay dividends in the future will be made at the discretion of PG&E Corporation's Board of Directors and will depend on, among other things, PG&E Corporation's results of operations, financial condition, cash requirements, contractual restrictions, and other factors that the Board of Directors may deem relevant.

PG&E Corporation is a holding company and relies on dividends, distributions and other payments, advances, and transfers of funds from the Utility to meet its obligations.

PG&E Corporation conducts its operations primarily through its subsidiary, the Utility, and substantially all of PG&E Corporation's consolidated assets are held by the Utility. Accordingly, PG&E Corporation's cash flow and its ability to meet its debt service obligations under its existing and future indebtedness are largely dependent upon the earnings and cash flows of the Utility and the distribution or other payment of these earnings and cash flows to PG&E Corporation in the form of dividends or loans or advances and repayment of loans and advances from the Utility. The ability of the Utility to pay dividends or make other advances, distributions, and transfers of funds will depend on its results of operations and may be restricted by, among other things, applicable laws limiting the amount of funds available for payment of dividends and certain restrictive covenants contained in the agreements of those subsidiaries. Additionally, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and to meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. In addition, the CPUC has imposed various conditions that govern the relationship between PG&E Corporation and the Utility, including financial conditions that require the Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. PG&E Corporation is unable to predict when it will commence the payment of dividends on its common stock. The deterioration of income from, or other available assets of, the Utility for any reason could limit or impair the Utility's ability to pay dividends or other distributions to PG&E Corporation, which could, in turn, materially and adversely affect PG&E Corporation's ability to meet its obligations.

California law and certain provisions in the Amended Articles and the amended and restated bylaws of PG&E Corporation (the "Amended Bylaws") may prevent efforts by shareholders to change the direction or management of PG&E Corporation.

The Amended Articles and the Amended Bylaws contain provisions that may make the acquisition of PG&E Corporation more difficult without the approval of the Board of Directors, including the following:

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until 2024, the Board of Directors will be divided into two equal classes, with members of each class elected in different years for different terms;

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only holders of shares who are entitled to cast ten percent or more of the votes can request a special meeting of the shareholders, and any such request must satisfy the requirements specified in the Amended Bylaws; action by shareholders may otherwise only be taken at an annual or special meeting duly called by or at the direction of a majority of the Board of Directors, or action by written consent signed by shareholders owning at least the number of votes necessary to authorize the action at a meeting where all shares entitled to vote were present;

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advance notice for all shareholder proposals is required; and

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any person acquiring PG&E Corporation Equity Securities will be restricted from owning 4.75% or more of such Equity Securities (as determined for federal income tax purposes (see "Tax Matters" in Item 7. MD&A)), subject to certain exceptions as may be determined by the Board of Directors of PG&E Corporation.

These and other provisions in the Amended Articles, the Amended Bylaws, and California law could make it more difficult for shareholders or potential acquirers to obtain control of the Board of Directors or initiate actions that are opposed by the then-current Board of Directors, including delaying or impeding merger, tender offer, or proxy contest involving PG&E Corporation. The existence of these provisions could negatively affect the price of PG&E Corporation common stock and limit opportunities for shareholders to realize value in a corporate transaction.

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.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been (beginning in March 2020) and could continue to be significantly affected by the outbreak of the COVID-19 pandemic (and its variants), but the extent of such impact is uncertain.

PG&E Corporation and the Utility continue to evaluate the impact of the current COVID-19 outbreak on their business and financial results. The consequences of a continued and prolonged outbreak and resulting governmental and regulatory orders have had and could continue to have a negative impact on the Utility's financial condition, results of operations, liquidity, and cash flows.

The outbreak of the COVID-19 pandemic and the resulting economic conditions, and resulting decrease in economic and industrial activity in the Utility's service area, have and will continue to have a significant adverse impact on the Utility's customers. These circumstances have impacted and will continue to impact the Utility for a period of time that PG&E Corporation and the Utility are unable to predict. For example, the economic downturn has resulted in a reduction in customer receipts and collection delays throughout the COVID-19 pandemic.

The Utility's accounts receivable balances over 30 days outstanding as of December 31, 2022 were approximately $1.1 billion, or $890 million higher as compared to the balances as of December 31, 2019. 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.

PG&E Corporation and the Utility are unable to quantify the long-term potential impact of the changes in customer collections or changes in energy demand on earnings and cash flows due, in part, to uncertainties regarding the timing, duration and intensity of the COVID-19 outbreak and the resulting economic downturn. Although the CPUC authorized the establishment of memorandum and balancing accounts to track costs associated with customer protection measures, the timing of regulatory relief, if any, and ultimate cost recovery from such accounts or otherwise, are uncertain.

The COVID-19 pandemic and resulting economic downturn have resulted and may continue to result in workforce disruptions, both in personnel availability (including a reduction in contract labor resources) and deployment. Increased governmental regulation of the COVID-19 pandemic protections, including vaccination mandates or testing requirements for workers, could result in employee attrition, workforce disruptions and increased supplier and contractor costs.

Although the Utility continues to prioritize customer and community safety, these disruptions necessitate changes to the Utility's operating and capital expenditure plans, which could lead to project delays or service disruptions in certain programs. Delays in production and shipping of materials used in the Utility's operations may also impact operations.

The Utility has experienced shortages in certain materials, longer lead times and delivery delays as a result of domestic and international raw material and labor shortages. If these disruptions to the supply chain persist or worsen, the Utility may be delayed or prevented from completing planned maintenance and capital projects work.

PG&E Corporation and the Utility expect additional financial impacts in the future as a result of the COVID-19 pandemic. Potential longer-term impacts of the COVID-19 pandemic on PG&E

Corporation or the Utility include the potential for higher credit spreads, borrowing costs and incremental financing needs. PG&E Corporation's and the Utility's analysis of the potential impact of the COVID-19 pandemic is ongoing and subject to change. PG&E Corporation and the Utility are unable to predict the timing, duration or intensity of the COVID-19 pandemic situation and any resurgence of the COVID-19 pandemic and any variant strains of the COVID-19 virus, the effectiveness and intensity of measures to contain the COVID-19 pandemic (including availability and effectiveness of vaccines), and the effects of the COVID-19 situation on the business, financial condition and results of operations of PG&E Corporation and the Utility and on the business and general economic conditions in the State of California and the United States of America.

Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE.

The rates paid by the Utility's customers are impacted by the Utility's costs, commodity prices, and broader energy trends. The Utility's capital investment plan, increasing procurement of renewable power and energy storage, increasing environmental regulations, leveling demand, and the cumulative impact of other public policy requirements, collectively place continuing upward pressure on customer rates. In particular, the Utility will need to make substantial, sustained investments to its infrastructure to adapt to climate change. For more information on factors that could cause the Utility's costs to increase, see "The Utility's ratemaking and cost recovery proceedings may not authorize sufficient revenues, or the Utility's actual costs could exceed its authorized or forecasted costs due to various factors, including if the Utility is not able to manage its costs effectively" above. If customer rates increase, the CPUC may face greater pressure to approve lesser amounts in the Utility's ratemaking or cost recovery proceedings.

The Utility generally recovers its electricity and natural gas procurement costs through rates as "pass-through" costs. Increases in the Utility's commodity costs directly impact customer bills.

Increasing levels of self-generation of electricity by customers (primarily solar installations) and customer enrollment in NEM, which allows self-generating customers to receive bill credits for power exported to the grid at the full retail rate, shifts costs to other customers. Under this structure, NEM customers do not pay their proportionate share of the cost of maintaining and operating the electric transmission and distribution system, including costs associated with funding social equity programs, subject to certain exceptions, while still receiving electricity from the system when their self-generation is inadequate to meet their electricity needs. These unpaid costs are subsidized by customers not participating in NEM. Accordingly, as more electric customers switch to NEM and self-generate energy, the burden on the remaining customers increases, which in turn encourages more self-generation, further increasing rate pressure on existing non-NEM customers.

Other long-term trends could also increase costs for gas customers. Natural gas suppliers are subject to compliance with CARB's cap-and-trade program, and natural gas end-use customers have an increasing exposure to carbon costs under the program through 2030 (when the full cost will be reflected in customer bills). CARB may also require aggressive energy efficiency programs to reduce natural gas end use. Increased renewable portfolio standards in the electric sector could reduce electric generation gas load. Additionally, customers replacing natural gas appliances with electric appliances will lead to further reduced gas demand. The combination of reduced load and increased costs to maintain the gas system could result in higher natural gas customer bills. In addition, some local city governments have passed ordinances restricting use of natural gas in new construction and, if other jurisdictions follow suit, this could affect future demand for the provision of natural gas. If fewer customers receive gas from the Utility, the Utility's gas system maintenance costs, many of which cannot be reduced in the short term even if gas quantities decrease, would be borne by fewer customers. Finally, a mandate to purchase renewable natural gas for core customers could lead to increased costs for core customers if utilities are competing with the transportation sector for supplies of renewable natural gas.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further reduce energy demand. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could increase the energy rates for other customers.

If rates were to rise too rapidly, customer usage could decline. This decline would decrease the volume of sales, among which the Utility's costs are allocated, and increase rates.

To relieve some of this upward rate pressure, the CPUC may authorize lower revenues than the Utility requested or increase the period over which the Utility is allowed to recover amounts, which could impact the Utility's ability to timely recover its operating costs. The Utility's level of authorized capital investment could decline as well, leading to a slower growth in rate base and earnings. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

Inflation may negatively impact PG&E Corporation's and the Utility's financial conditions, results of operations, liquidity, and cash flows.

PG&E Corporation and the Utility have observed that prices for equipment, materials, supplies, employee labor, contractor services, and variable-rate debt have increased. Long-term inflationary pressures may result in such prices continuing to increase more quickly than expected. Increases in inflation raises costs for labor, materials and services, and PG&E Corporation and the Utility may be unable to secure these resources on economically acceptable terms or offset such costs with increased revenues, operating efficiencies, or cost savings, which may adversely impact PG&E Corporation's and the Utility's financial conditions, results of operations, liquidity, and cash flows.

Section: Item7

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

OVERVIEW

This is a combined report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

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 Wildfires, Wildfire Mitigation, and Associated Cost Recovery.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the costs and effectiveness of the Utility's wildfire mitigation initiatives; the extent of damages from wildfires that do occur; the financial impacts of wildfires; and PG&E Corporation's and the Utility's ability to mitigate those financial impacts with insurance, the Wildfire Fund, and regulatory recovery.

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 Utility's wildfire mitigation initiatives include EPSS, PSPS, vegetation management, asset inspections, and system hardening. In particular, in 2022 the Utility expanded the EPSS program to all high fire risk areas. The Utility is also focused on undergrounding more lines each year while using economies of scale to make undergrounding more cost efficient. These initiatives significantly reduced the number of CPUC-reportable ignitions and the number of acres burned. The success of the Utility's wildfire mitigation efforts depends on many factors, including whether the Utility is able to retain or contract for the workforce necessary to execute its wildfire mitigation actions.

PG&E Corporation and the Utility have incurred and will continue to incur substantial expenditures in connection with these initiatives. For more information on incurred expenditures, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8. The extent to which the Utility will be able to recover these expenditures and other potential costs through rates is uncertain. If additional requirements are imposed that go beyond current expectations, such requirements could have a substantial impact on the costs of the Utility's wildfire mitigation initiatives.

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 and OEIS as its review progresses. 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. See "Self-Reports to the CPUC" in "Regulatory Matters" below.

Despite these extensive measures, 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. Once an ignition has occurred, the Utility is unable to control the extent of damages, which is primarily determined by environmental conditions (including weather and vegetation conditions), third-party suppression efforts, and the location of the wildfire.

The financial impact of past wildfires is significant. As of December 31, 2022, PG&E Corporation and the Utility had recorded aggregate liabilities of $1.025 billion, $400 million, $1.175 billion, and $100 million for claims in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire, respectively, and in each case before available insurance, and, in the case of the 2021 Dixie fire and the 2022 Mosquito fire, other probable cost recoveries. These liability amounts correspond to the lower end of the range of reasonably estimable probable losses but do not include all categories of potential damages and losses.

On September 24, 2021, the Shasta County District Attorney's Office charged the Utility with 31 counts in connection with the 2020 Zogg fire, of which the court has dismissed 20 counts. If the Utility were to be convicted of any of the remaining charges, the Utility could be subject to material fines, penalties, and restitution, as well as non-monetary remedies such as oversight requirements.

Accordingly, depending on which charges the Utility were to be convicted of, its total losses associated with the 2020 Zogg fire could materially exceed the $400 million of aggregate liability that PG&E Corporation and the Utility have recorded.

PG&E Corporation and the Utility may be able to mitigate the financial impact of future wildfires in excess of insurance coverage through the Wildfire Fund, or cost recovery through rates. Each of these mitigations involves uncertainties, and liabilities could exceed available recoveries. See "Loss Recoveries" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Recorded liabilities in connection with the 2019 Kincade fire and the 2021 Dixie fire have already exceeded potential amounts recoverable under applicable insurance policies. As of December 31, 2022, the Utility has recorded insurance receivables of $430 million for the 2019 Kincade fire, $370 million for the 2020 Zogg fire, $530 million for the 2021 Dixie fire, and $45 million for the 2022 Mosquito fire. Additionally, the Utility does not expect that any of its liability insurance would cover restitution payments, if such payments were ordered by the court presiding over the criminal proceeding in connection with the 2020 Zogg fire.

If the eligible claims for liabilities arising from wildfires were to exceed $1.0 billion in any Wildfire Fund coverage year ("Coverage Year"), the Utility may be eligible to make a claim against the Wildfire Fund under AB 1054 for such excess amount. The Wildfire Fund is available to the Utility to pay eligible claims for liabilities arising from wildfires, 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. 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 therefore not subject to reimbursement, and whether the benefits of participating in the Wildfire Fund ultimately outweigh its substantial costs. Finally, recoveries for the 2019 Kincade fire would be subject to a 40% limitation on the allowed amount of claims arising before emergence from bankruptcy. As of December 31, 2022, the Utility has recorded a Wildfire Fund receivable of $175 million for the 2021 Dixie fire. See "Wildfire Fund under AB 1054" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility will be permitted to recover its wildfire-related claims and legal fees through rates only if the CPUC or the FERC, as applicable, determines that the Utility has met the prudency standard. The revised prudency standard under AB 1054 has not been interpreted or applied by the CPUC, and it is possible that the CPUC could interpret the standard or apply it to the relevant facts differently from how the Utility has interpreted and applied the standard, in which case the Utility may not be able to recover all or a portion of expenses that it has recorded as receivables. As of December 31, 2022, the Utility has recorded receivables for regulatory recovery of $503 million for the 2021 Dixie fire and $60 million for the 2022 Mosquito fire. See "2021 Dixie Fire," and "2022 Mosquito Fire" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8 for more information.

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The Timing and Outcome of Ratemaking and Other Proceedings.

Regulatory ratemaking proceedings are a key aspect of the Utility's business. The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administrative and general expenses) and capital costs (e.g., depreciation and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to pass through to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" below), including its costs to procure electricity and natural gas for customers and to administer public purpose and customer programs. Although the Utility generally seeks to recover its recorded costs on a timely basis, in recent years, the amount of the costs recorded in memorandum and balancing accounts has increased. The Utility has also applied to transfer its non-nuclear generation assets to Pacific Generation and potentially sell a minority interest in Pacific Generation. The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potential rate impacts, the regulatory and political environments, and other factors. See Notes 4 and 16 of the Notes to the

Consolidated Financial Statements in Item 8 and "Regulatory Matters" below.

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The Outcome of Other Enforcement, Litigation, and Regulatory Matters, and Other Government Proposals.

The Utility is subject to enforcement, litigation, and regulatory matters, including those described above, the Safety Culture OII, EOEP proceedings, and actions in connection with the Utility's WMP, and safety and other self-reports. See Note 16 of the Notes to the Consolidated Financial Statements in Item 8. 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, actions 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. See "Jurisdictions may attempt to acquire the Utility's assets through eminent domain" in Item 1A. Risk Factors for more information. These matters could result in penalties, additional regulatory requirements, or changes to the Utility's operations. PG&E Corporation and the Utility seek to limit these matters by implementing a robust compliance program and by delivering excellent customer experiences.

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PG&E Corporation's and the Utility's Ability to Control Operating Costs.

Under cost-of-service ratemaking, a utility's earnings depend on its ability to manage costs within the amounts authorized for recovery in its ratemaking proceedings. The Utility has set a goal to increase its capital investments to meet safety and climate goals, while also reducing non-fuel Operating and maintenance costs by two percent per year. The Utility's ability to meet this goal depends on whether the Utility can improve the planning and execution of its work by continuing to implement the Lean operating system.

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 addition, this annual 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 "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.

Tax Matters

PG&E Corporation had a U.S. federal net operating loss carryforward of approximately $26.6 billion and California net operating loss carryforward of approximately $25.2 billion as of December 31, 2022.

Under Section 382 of the IRC, 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 (as defined in the Amended Articles) without approval by the Board of Directors of PG&E Corporation (the "Ownership Restrictions"). As discussed below under "Update on Ownership Restrictions in PG&E Corporation's Amended Articles," due to the election to treat the Fire Victim Trust as a grantor trust for income tax purposes, the calculation of Percentage Stock 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, the Utility, and ShareCo. 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 IRC.

Furthermore, the activities of the Fire Victim Trust are treated as activities of the Utility for tax purposes. Accordingly, PG&E Corporation will recognize income tax benefits and the corresponding DTA as the Fire Victim Trust sells shares of PG&E Corporation common stock, and the amounts of such benefits and assets 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. At various dates throughout 2022, the Fire Victim Trust exchanged Plan Shares for an equal number of New Shares in the manner contemplated by the Share Exchange and Tax Matters Agreement; in each case, the Fire Victim Trust thereafter reported that it sold the applicable New Shares. During the year ended December 31, 2022, the Fire Victim Trust's sale of PG&E Corporation common stock in the aggregate amount of 230,000,000 shares resulted in an aggregate tax benefit of $870 million recorded in PG&E Corporation's and the Utility's Consolidated Financial Statements.

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

As a result of the grantor trust election, shares of PG&E Corporation common stock owned by the Fire Victim Trust are treated as held by the Utility and, in turn, attributed to PG&E Corporation for income tax purposes. Consequently, any shares of PG&E Corporation common stock owned by the Fire Victim Trust, along with any shares owned by the Utility directly, are effectively excluded from the total number of outstanding equity securities when calculating a person's Percentage Stock Ownership (as defined in the Amended Articles) for purposes of the 4.75% ownership limitation in the Amended Articles. Shares owned by ShareCo are also effectively excluded because ShareCo is a disregarded entity for income tax purposes. For example, although PG&E Corporation had 2,466,208,388 shares outstanding as of February 16, 2023, only 1,800,721,208 shares (the number of outstanding shares of common stock less the number of shares held by the Fire Victim Trust, the

Utility, 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 taking into account the shares of PG&E Corporation common stock known to have been sold by the Fire Victim Trust as of February 16, 2023, a person's effective Percentage Stock Ownership limitation for purposes of the Amended Articles as of February 16, 2023 was 3.46% of outstanding shares. As of February 16, 2023, to the knowledge of PG&E Corporation, the Fire Victim Trust had sold 290,000,000 shares of PG&E Corporation common stock in the aggregate.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2022 and 2021. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

See "Results of Operations" in Item 7 of the 2021 Form 10-K for discussion of results of operations for 2021 compared to 2020.

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders:

(in millions)

2022

2021

Consolidated Total

$

1,800

$

(102)

PG&E Corporation

(412)

(226)

Utility

2,212

124

PG&E Corporation's net loss primarily consists of income taxes and interest expense on long-term debt. The increase in PG&E Corporation's net loss for 2022, as compared to 2021, is primarily due to increased interest rates on long-term debt.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2022 and 2021. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs do not impact earnings.

63

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.

2022

2021

Revenues and Costs:

Revenues and Costs:

(in millions)

That Impacted Earnings

That Did Not Impact Earnings

Total Utility

That Impacted Earnings

That Did Not Impact Earnings

Total Utility

Electric operating revenues

$

10,357

$

4,703

$

15,060

$

9,542

$

5,589

$

15,131

Natural gas operating revenues

3,939

2,681

6,620

3,753

1,758

5,511

Total operating revenues

14,296

7,384

21,680

13,295

7,347

20,642

Cost of electricity

--

2,756

2,756

--

3,232

3,232

Cost of natural gas

--

2,100

2,100

--

1,149

1,149

Operating and maintenance

6,737

2,988

9,725

6,820

3,374

10,194

SB 901 securitization charges, net

608

--

608

--

--

--

Wildfire-related claims, net of insurance recoveries

237

--

237

258

--

258

Wildfire Fund expense

477

--

477

517

--

517

Depreciation, amortization, and decommissioning

3,856

--

3,856

3,403

--

3,403

Total operating expenses

11,915

7,844

19,759

10,998

7,755

18,753

Operating income (loss)

2,381

(460)

1,921

2,297

(408)

1,889

Interest income

162

--

162

22

22

Interest expense

(1,658)

--

(1,658)

(1,373)

--

(1,373)

Other income, net

135

460

595

104

408

512

Reorganization items, net

--

--

--

(12)

--

(12)

Income before income taxes

$

1,020

$

--

$

1,020

$

1,038

$

--

$

1,038

Income tax provision (benefit)

(1)

(1,206)

900

Net income

2,226

138

Preferred stock dividend requirement

(1)

14

14

Income Attributable to Common Stock

$

2,212

$

124

(1)

These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2022 and 2021, 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 $1.0 billion, or 8%, in 2022 compared to 2021, primarily due to the recognition of approximately $310 million in revenues related to the settlement agreement for the 2018 CEMA application (see "2018 CEMA Application" below), the recognition of approximately $180 million in revenues related to the final decision approving $356.3 million in revenue requirements for capital expenditures incurred in the period from 2011 through 2014 for its GT&S system (see "2015 Gas Transmission and Storage Rate Case" below), increased base revenues authorized in the 2020 GRC, and additional revenues as authorized through the FERC formula rate. In addition, the Utility recognized approximately $113 million in nuclear decommissioning revenues in 2022 with no comparable revenues in 2021. This is consistent with the 2018 NDCTP final decision that authorized no decommissioning revenues for 2021 and $113 million in revenues in 2022. These increases were partially offset by a decrease of approximately $180 million of previously deferred revenues recognized in conjunction with interim rate relief collected in 2021 associated with the 2020 WMCE application (see "2020 WMCE Application" below).

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings decreased by $83 million, or 1%, in 2022 compared to 2021, as a result of operating cost efficiencies and decreases in the recognition of previously deferred costs including $90 million related to residential uncollectibles and approximately $180 million recognized in conjunction with interim rate relief associated with the 2020 WMCE application (see "2020 WMCE Application" below). In addition, during the year ended December 31, 2021, the Utility recorded a $124 million charge related to the September 21, 2021 joint motion for approval of settlement agreement associated with the 2020 WMCE filing, with no comparable charge in the same period in 2022. These decreases were partially offset by the recognition of approximately $310 million of previously deferred expenses, which were authorized by the settlement agreement for the 2018 CEMA application (see "2018 CEMA Application" below) in the year ended December 31, 2022, compared to the same period in 2021.

SB 901 Securitization Charges, Net

SB 901 securitization charges, net, that impacted earnings increased by $608 million, or 100%, in 2022 compared to 2021. During the year ended December 31, 2022, the Utility recorded $608 million in net SB 901 securitization charges, for inception of the regulatory asset and liability pursuant to the CHT decision, as well as tax benefits realized within income tax expense in the current year related to the Fire Victim Trust's sale of PG&E Corporation common stock, with no comparable charges in 2021. For more information, see Note 6 of the Notes to the Consolidated Financial Statements in Item 8 below.

Wildfire-Related Claims, Net of Recoveries

Costs related to wildfires that impacted earnings decreased by $21 million, or 8%, in 2022 compared to 2021. The Utility recognized pre-tax charges of $225 million related to the 2019 Kincade fire, $100 million related to the 2022 Mosquito fire, $25 million related to the 2021 Dixie fire, and $25 million related to the 2020 Zogg fire in the year ended December 31, 2022. These charges were partially offset by $95 million of probable recoveries through insurance and the WEMA related to the 2022 Mosquito fire and $25 million in probable recoveries through the Wildfire Fund related to the 2021 Dixie fire. The Utility recognized pre-tax charges of $1.15 billion related to the 2021 Dixie fire, $175 million related to the 2019 Kincade fire, and $100 million related to the 2020 Zogg fire in the year ended December 31, 2021, partially offset by $1.06 billion of probable recoveries through insurance, the WEMA, and the Wildfire Fund related to the 2021 Dixie fire and $100 million of probable insurance recoveries related to the 2020 Zogg fire in the year ended December 31, 2021. See "Loss Recoveries" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8 below.

In addition to the probable wildfire-related recoveries noted above, the Utility has recorded $125 million of probable recoveries through FERC TO formula rates, which are recorded as a reduction to regulatory liabilities and are not captured in wildfire-related claims.

See Item 1A. Risk Factors and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Wildfire Fund Expense

Wildfire Fund expense that impacted earnings decreased by $40 million, or 8%, in 2022 compared to 2021, primarily due to accelerated amortization of the Wildfire Fund asset recorded in 2021 as a result of the Wildfire Fund receivable accrued in relation to the 2021 Dixie fire, with no material amounts recorded in 2022.

See Notes 3 and 15 of the Notes to the Consolidated Financial Statements in Item 8.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $453 million, or 13%, in 2022 compared to 2021, primarily due to an increase in net capital additions and an increase in decommissioning expense beginning in January 2022 primarily as a result of the final 2018 NDCTP decision.

Interest Income

The Utility's interest income that impacted earnings increased by $140 million, or 636%, in 2022 compared to 2021, primarily due to higher interest rates earned on regulatory balancing accounts.

Interest Expense

Interest expense that impacted earnings increased by $285 million, or 21%, in 2022 compared to 2021, primarily due to the issuance of additional long-term debt and an increase in interest rates on variable-rate debt.

Other Income, Net

Changes to Other income, net that impact earnings are primarily driven by fluctuations in the balance of construction work in progress that impact the equity component of AFUDC, and gains and losses on equity securities held by the customer credit trust.

Income Tax Provision (Benefit)

Income tax benefit increased by $2.1 billion in 2022 compared to 2021, primarily due to a write-off of a DTA associated with the grantor trust election for the Fire Victim Trust in the year ended December 31, 2021 and a benefit recognized related to the sale of shares in the Fire Victim Trust in the year ended December 31, 2022.

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

2022

2021

Federal statutory income tax rate

21.0

%

21.0

%

Increase (decrease) in income tax rate resulting from:

State income tax (net of federal benefit)

(1)

(26.9)

%

24.1

%

Effect of regulatory treatment of fixed asset differences

(2)

(49.2)

%

(51.6)

%

Tax credits

(1.3)

%

(1.2)

%

Fire Victim Trust

(3)

(64.0)

%

91.9

%

Other, net

2.2

%

2.6

%

Effective tax rate

(118.2)

%

86.8

%

(1)

Includes the effect of state flow-through ratemaking treatment and the effect of the grantor trust election.

(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 record 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. 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.

(3)

Includes the tax benefit of the sale of shares by the Fire Victim Trust in 2022 and the tax effect of the grantor trust election for the Fire Victim Trust in 2021. See "Tax Matters" above and Note 7 of the Notes to the Consolidated Financial Statements in Item 8.

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 11 of the Notes to the Consolidated Financial Statements in Item 8. 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. The cost of electricity decreased in 2022 as compared to 2021. This was primarily due to decreased customer demand and higher energy sales to the CAISO, partially offset by higher fuel prices.

(in millions)	2022	2021
Cost of purchased power, net	$ 2,283	$ 2,883
Fuel used in own generation facilities	473	349
Total cost of electricity	$ 2,756	$ 3,232

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 11 of the Notes to the Consolidated Financial Statements in Item 8. The cost of natural gas increased in 2022 as compared to 2021 due to increased customer demand and higher market prices. This was driven primarily by below-normal winter temperatures and prolonged drought conditions, resulting in lower California and Pacific Northwest hydro-electric generation output and higher demand from natural-gas fired generation.

Lower natural gas storage levels and regional pipeline constraints also contributed to higher natural gas prices.

(in millions)	2022	2021
Cost of natural gas sold	$ 1,957	$ 1,010
Transportation cost of natural gas sold	143	139
Total cost of natural gas	$ 2,100	$ 1,149

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.

Nuclear Operations

Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, reflect the availability of Diablo Canyon's generation to the California electricity market. Management analyzes capacity factors by comparing Diablo Canyon's actual generation to forecasted annual capacity factors, which reflect planned refueling outages, curtailments for condenser cleaning, allowances for minor curtailments resulting from equipment issues, and curtailments for major ocean storms.

Apart from cost-of-service ratemaking and beginning on September 2, 2022, the Utility is entitled to receive a monthly performance-based disbursement. For more information, see "Extension of Diablo Canyon Operations" below.

The Utility manages its scheduled refueling outages with the objective of minimizing their duration and maintaining high nuclear generating capacity factors, resulting in a stable generation base for the Utility's wholesale and retail power marketing activities. During scheduled refueling outages, the Utility performs maintenance and equipment upgrades to minimize the occurrence of unplanned outages and to maintain safe, reliable operations. For the years ended December 31, 2022 and 2021, Diablo Canyon achieved an average capacity factor of 90% and 84%, respectively. As previously disclosed, Diablo Canyon Unit 2 experienced five outages between July 2020 and April 2021, each due or related to excessive vibrations within the main generator.

In addition to the maintenance and equipment upgrades performed by the Utility during scheduled refueling outages, the Utility has extensive operating and security procedures in place to assure the safe operation of Diablo Canyon. The Utility also has extensive safety systems in place designed to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

PG&E Corporation and the Utility expect to have sufficient liquidity to fund their present and future commitments.

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 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 impact 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.

PG&E Corporation and the Utility have various contractual commitments which impact cash requirements. These commitments are discussed in "Purchase Commitments" in Note 16 of the

Arrearages Related to 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 the COVID-19 pandemic. The outbreak of the COVID-19 pandemic, the emergence of variant strains of the virus (including Delta and Omicron), 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 impacted and will continue to impact the Utility for an indeterminate period of time. In particular, the Utility continues to experience increased arrearages. 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, an annual cap set by the CPUC on the number of service disconnections for residential customers, and the CPUC's "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections." The Utility resumed non-residential and residential service disconnections as of October 13, 2022. The Utility's accounts receivable balances over 30 days outstanding as of December 31, 2022, were approximately $1.1 billion, or $890 million higher as compared to the balance as of December 31, 2019. The Utility is unable to estimate the portion of the increase directly attributable to the COVID-19 pandemic.

As of December 31, 2022, PG&E Corporation and the Utility had access to approximately $2.9 billion of total liquidity comprised of approximately $609 million of Utility cash, $125 million of PG&E Corporation cash and $2.2 billion of availability under PG&E Corporation's and the Utility's revolving credit facilities. The 2022 cost of capital application was filed off-cycle based on the extraordinary event of the COVID-19 pandemic and related government response. See "Cost of Capital Proceedings" below for more information.

The Utility established the CPPMA for tracking costs related to the CPUC's emergency authorization and order for the period the CPPMA was in effect. As of December 31, 2022, the CPPMA totaled

$26 million and is reflected in Long-term regulatory assets on the Consolidated Balance Sheets. In addition to the $26 million recorded to the CPPMA, the Utility recorded approximately $126 million of under-collections from residential customers from March 4, 2020 to December 31, 2022 to the RUBA, which has been approved by the CPUC and is reflected in Regulatory balancing accounts receivable on the Consolidated Balance Sheets.

On June 30, 2022, the Governor of California signed AB 205, which included authorization for additional incremental CAPP funding of $958 million for California IOUs. The Utility received approximately $200 million in November 2022 to reduce the amounts owed by customer accounts in arrears. The amount of funding was determined by the California Department of Community Services and Development, which is the agency responsible for administering the CAPP.

Because electric rates have been set using a sales forecast that has been adjusted for impacts of the COVID-19 pandemic, PG&E Corporation and the Utility do not expect significant variances between the forecast of electric usage and actual electric usage due to COVID-19 in 2023. Consequently, PG&E Corporation and the Utility do not expect the COVID-19 pandemic to result in undercollections.

The COVID-19 pandemic may continue to impact PG&E Corporation and the Utility financially, and PG&E Corporation and the Utility will continue to monitor the overall impact of the COVID-19 pandemic.

Cash, Cash Equivalents, and Restricted Cash

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of AB 1054 and SB 901 fixed recovery charge collections that are to be used to service the associated bonds.

Financial Resources

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 (each as defined in "At the Market Equity Distribution Program" in Note 7 of the Notes to the Consolidated Financial Statements in Item 8), 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 (as defined in "At the Market Equity Distribution Program" in Note 7 of the Notes to the Consolidated Financial Statements in Item 8) with the Forward Purchasers. On October 31, 2022, PG&E Corporation suspended the At the Market Equity Distribution Program until further notice. As of the suspension date for this program, PG&E Corporation had not sold any shares pursuant to the Equity Distribution Agreement.

PG&E Corporation and the Utility plan to meet their capital requirements for 2023 through internally generated funds and the issuance of long-term debt, short-term debt, and the potential sale of a minority interest in Pacific Generation. (See "Application with Pacific Generation LLC for Approval to Transfer Non-Nuclear Generation Assets" below.) PG&E Corporation does not plan to issue any equity securities in 2023 or 2024. Factors that could affect PG&E Corporation's planned equity issuances include liquidity and cash flow needs, capital expenditures, interest rates, the timing and outcome of ratemaking proceedings, and the timing and terms of other financings, including the potential sale of a minority interest in Pacific Generation.

Debt Financings

On February 18, 2022, the Utility completed the sale of (i) $1 billion aggregate principal amount of 3.25% First Mortgage Bonds due 2024, (ii) $400 million aggregate principal amount of 4.20% First Mortgage Bonds due 2029, (iii) $450 million aggregate principal amount of 4.40% First Mortgage Bonds due 2032 and (iv) $550 million aggregate principal amount of 5.25% First Mortgage Bonds due 2052. The proceeds were used for the prepayment of a portion of the 18-month tranche loans pursuant to an existing term loan credit agreement (the "2020 Utility Term Loan Credit Agreement"), in an amount equal to $1.0 billion, and for general corporate purposes.

On June 8, 2022, the Utility issued $450 million aggregate principal amount of 4.950% First Mortgage Bonds due June 8, 2025, $450 million aggregate principal amount of 5.450% First Mortgage Bonds due June 15, 2027, and $600 million aggregate principal amount of 5.90% First Mortgage Bonds due June 15, 2032. The proceeds were used for the repayment of borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

On January 6, 2023, the Utility completed the sale of (i) $750 million aggregate principal amount of 6.150% First Mortgage Bonds due 2033 and (ii) $750 million aggregate principal amount of 6.750% First Mortgage Bonds due 2053. The proceeds were used for the repayment of a portion of the loans outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

SB 901 Securitization

On May 10, 2022, PG&E Wildfire Recovery Funding LLC issued $3.6 billion aggregate principal amount of senior secured recovery bonds (the "Series 2022-A Recovery Bonds"). The Series 2022-A Recovery Bonds were issued in five tranches:

Tranche

Amount

Interest Rate

Final Maturity Date

A-1

$

540,000,000

3.594

%

June 1, 2032

A-2

$

540,000,000

4.263

%

June 1, 2038

A-3

$

360,000,000

4.377

%

June 3, 2041

A-4

$

1,260,000,000

4.451

%

December 1, 2049

A-5

$

900,000,000

4.674

%

December 1, 2053

70

The net proceeds were used to fund the redemption of all $500 million aggregate principal amount of the Utility's Floating Rate First Mortgage Bonds due June 16, 2022 on May 16, 2022 and the redemption of all $2.5 billion aggregate principal amount of the Utility's 1.75% First Mortgage Bonds due June 16, 2022 on May 16, 2022. The Utility used the remaining proceeds from the issuance of the Series 2022-A Recovery Bonds for the repayment of a portion of loans outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

On July 20, 2022, PG&E Wildfire Recovery Funding LLC issued $3.9 billion aggregate principal amount of senior secured recovery bonds (the "Series 2022-B Recovery Bonds"). The Series 2022-B Recovery Bonds were issued in five tranches:

Tranche	Amount	Interest Rate	Final Maturity Date
B-1	$ 613,080,000	4.022 %	June 1, 2033
B-2	$ 600,000,000	4.722 %	June 1, 2039
B-3	$ 500,040,000		

5.081

%

June 3, 2043

B-4

$

1,149,960,000

5.212

%

December 1, 2049

B-5

$

1,036,920,000

5.099

%

June 1, 2054

The net proceeds were used to fund (1) the redemption of all $1.5 billion aggregate principal amount of the Utility's 1.367% First Mortgage Bonds due March 10, 2023 on July 25, 2022, (2) the prepayment of all $500 million of loans outstanding under the 2022A Utility Term Loan Credit Agreement as defined below, and (3) the repayment of a portion of loans outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement. The Utility also intends to use a portion of the remaining proceeds to fund the redemption of all $1.0 billion aggregate principal amount of the Utility's 3.25% First Mortgage Bonds due 2024.

AB 1054 Securitization

On November 30, 2022, PG&E Recovery Funding LLC issued approximately $983 million of Series 2022-A Senior Secured Recovery Bonds. The senior secured recovery bonds were issued in three tranches: (1) approximately $215 million with an interest rate of 5.045% due July 15, 2034, (2) approximately $200 million with an interest rate of 5.256% due January 15, 2040, and (3) approximately $568 million with an interest rate of 5.536% due July 15, 2049. The net proceeds were used by the Utility to fund fire risk mitigation capital expenditures that were incurred by the Utility from the period beginning October 2021 through October 2022.

For more information, see "AB 1054" in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

Credit Facilities

As of December 31, 2022, PG&E Corporation and the Utility had $500 million and $1.5 billion available under their respective $500 million and $4.4 billion revolving credit facilities. The Utility also has access to the Receivables Securitization Program, under which the Utility may borrow the lesser of the facility limit and the facility availability. The facility limit fluctuates between $1.0 billion and $1.5 billion depending on the periods set forth in the amendment. Further, 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.

Utility

On March 31, 2022, the Utility prepaid in full the remaining portion of the 18-month tranche loans pursuant to the 2020 Utility Term Loan Credit Agreement, in a principal amount equal to $298 million. As a result of such prepayment, the 2020 Utility Term Loan Credit Agreement was terminated and is no longer outstanding.

On April 4, 2022, the Utility entered into a term loan credit agreement (the "2022A Utility Term Loan Credit Agreement"), comprised of 364-day tranche loans in the aggregate principal amount of $500 million (the "364-Day 2022A Tranche Loans"). On July 21, 2022, the 364-Day 2022A Tranche Loans were prepaid in full with a portion of the proceeds from issuance of the Series 2022-B Recovery Bonds. As a result of such prepayment, the 2022A Utility Term Loan Credit Agreement was terminated and is no longer outstanding.

On April 20, 2022, the Utility entered into a term loan credit agreement (the "2022B Utility Term Loan Credit Agreement"), comprised of 364-day tranche loans in the aggregate principal amount of $125 million (the "364-Day 2022B Tranche Loans") and two-year tranche loans in the aggregate principal amount of $400 million (the "2-Year 2022B Tranche Loans"). The 364-Day 2022B Tranche Loans have a maturity date of April 19, 2023 and the 2-Year 2022B Tranche Loans have a maturity date of April 19, 2024. The 364-Day 2022B Tranche Loans and the 2-Year 2022B Tranche Loans bear interest based on the Utility's election of either (1) the Term Secured Overnight Financing Rate (plus a 0.10% credit spread adjustment) plus an applicable margin of 1.25%, or (2) the base rate plus an applicable margin of 0.25%. The Utility borrowed the entire amount of the 364-Day 2022B Tranche Loans and the 2-Year 2022B Tranche Loans on April 20, 2022.

On April 20, 2022, the Utility entered into an amendment to the Receivables Securitization Program to, among other things, add an uncommitted incremental facility which, subject to certain conditions precedent, allows the SPV to request an increase in the facility limit by an additional $500 million to an aggregate amount of $1.5 billion. On August 12, 2022, the SPV made such a request to increase the facility limit, and the facility limit was subsequently increased to $1.5 billion on August 22, 2022. On September 30, 2022, the Utility entered into an amendment to the Receivables Securitization Program to, among other things, (i) extend the scheduled termination date to September 30, 2024 and (ii) implement a seasonal facility limit. After giving effect to the amendment, the facility limit fluctuates between $1.0 billion and $1.5 billion based on the periods set forth in the amendment.

On July 1, 2020, the Utility entered into the Utility Revolving Credit Agreement, which it subsequently amended. On October 4, 2022, the Utility further amended the Utility Revolving Credit Agreement to, among other things, (i) increase the aggregate commitments provided by the lenders to $4.4 billion and (ii) extend the maturity date of such agreement to June 22, 2027 (subject to a one-year extension at the option of the Utility).

PG&E Corporation

On July 1, 2020, PG&E Corporation entered into the Corporation Revolving Credit Agreement, which it subsequently amended. On October 4, 2022, PG&E Corporation further amended the Corporation Revolving Credit Agreement to, among other things, extend the maturity date of such agreement to June 22, 2025 (subject to a one-year extension at the option of PG&E Corporation).

For more information, see "Credit Facilities" in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

Intercompany Note Payable

On August 11, 2021, PG&E Corporation borrowed $145 million from the Utility under an interest bearing 364-day intercompany note due August 10, 2022. On June 17, 2022, this loan was repaid in full.

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.

On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, which was paid on May 13, 2022, to holders of record on April 29, 2022. In addition to the dividends paid in arrears, the Utility paid approximately $11 million of dividends on redeemable preferred stock during the year ended December 31, 2022. On December 15, 2022, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock totaling $3.5 million, which was paid on February 15, 2023, to holders of record on January 31, 2023.

On June 15, 2022, the Board of Directors of the Utility also reinstated the dividend on the Utility's common stock and declared a common stock dividend of $425 million that was paid to PG&E Corporation on June 17, 2022. On September 15, 2022, the Board of Directors of the Utility declared a common stock dividend of $425 million that was paid to PG&E Corporation on September 16, 2022. On December 15, 2022, the Board of Directors of the Utility declared a common stock dividend of $425 million that was paid to PG&E Corporation on December 20, 2022.

No dividend is payable until declared by the Board of Directors of the Utility.

Subject to the dividend restrictions described in Note 7 of the Notes to the Consolidated Financial Statements in Item 8, any decision to declare and pay dividends on PG&E Corporation's common stock in the future will be made at the discretion of the Board of Directors and will depend on, among other things, results of operations, financial condition, cash requirements, contractual restrictions of PG&E Corporation, and other factors that the Board of Directors of PG&E Corporation may deem relevant. Pursuant to the Confirmation Order, PG&E Corporation may not pay dividends on shares of its common stock until it recognizes $6.2 billion in Non-GAAP Core Earnings following the Emergence Date. "Non-GAAP Core Earnings" means GAAP earnings adjusted for certain non-core items as described in the Plan. PG&E Corporation is unable to predict when it will commence the payment of dividends on its common stock.

Utility Cash Flows

PG&E Corporation's consolidated cash flows consist primarily of cash flows related to the Utility. The following discussion presents the Utility's cash flows for 2022 and 2021.

See "Liquidity and Financial Resources" in Item 7 of the 2021 Form 10-K for discussion of the Utility's cash flows for 2021 compared to 2020.

The Utility's cash flows were as follows:

Year Ended December 31,				
(in millions)		2022		2021
Net cash provided by (used in) operating activities	$	3,831	$	2,448

Net cash used in investing activities

(10,069)

(7,050)

Net cash provided by financing activities

6,879

4,379

Net change in cash, cash equivalents, and restricted cash

$

641

$

(223)

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 2022, net cash provided by operating activities increased by $1.4 billion compared to the same period in 2021. This increase was partially due to an increase in base revenues authorized in the 2020 GRC and additional revenues as authorized through the FERC formula rate and a decrease in operating and maintenance expense as a result of operating cost efficiencies. In addition, during 2022, the Utility made a payment to the Fire Victim Trust of $592 million as compared to a payment of $758 million in the same period in 2021.

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

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the timing and amount of costs in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, and the 2022 Mosquito fire and the timing and amount of any potential related insurance, Wildfire Fund, and regulatory 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 "Wildfire-Related Securities Class Action" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8 and "Regulatory Matters" below for more information);

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the severity, extent and duration of the global COVID-19 pandemic and its impact on the Utility's service area, the ability of the Utility to collect on its customer receivables, 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 through rates any losses incurred in connection with the COVID-19 pandemic, as well as the impact of the COVID-19 pandemic on the availability or cost of financing;

-

the timing and amounts of available funds to pay eligible claims for liabilities arising from future wildfires;

-

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

-

the timing and amounts of available funds collected for self-insurance (see "2023 General Rate Case" in the Regulatory Matters section of Item 7. Management's Discussion and Analysis for more information);

-

the timing of the gain to be returned to customers from the sale of the SFGO and transmission tower wireless licenses and the amounts incurred related to the move to and the leasing 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.

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed under "Purchase Commitments" in Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Investing Activities

Net cash used in investing activities increased by $3.0 billion during 2022 as compared to the same period in 2021. This increase was primarily driven by a $1.9 billion increase in capital expenditures, including additional system hardening and emergency response work performed in 2022. Additionally, the Utility purchased $1.0 billion of investments as part of the creation of the customer credit trust, with no similar purchases in 2021.

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 and customer credit trust investments which are partially offset by the amount of cash used to purchase new nuclear decommissioning trust and customer credit 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. Pursuant to SB 901, the funds in the customer credit trust, along with accumulated earnings, are used exclusively to fund a monthly credit to customers that is anticipated to equal the fixed recovery charges such that the SB 901 securitization is designed to be rate neutral to customers.

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 $7.9 billion and $11.2 billion in 2023. Additionally, future cash flows used in investing activities will be impacted by the timing and amount related to the intended purchase of the Lakeside Building, and the timing and amount of contributions to the customer credit trust, including shareholder tax benefits, and $1.0 billion of cash to be contributed in 2024.

Financing Activities

Net cash provided by financing activities increased by $2.5 billion during 2022 as compared to the same period in 2021. The increase was primarily due to the issuance of $7.5 billion of SB 901 recovery bonds and a decrease of $850 million in net repayments of short-term debt. These increases were partially offset by a $5.9 billion increase in amounts paid to satisfy long-term debt outstanding in 2022 compared to the same period in 2021.

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, the Utility's future cash flows from financing activities will be affected by the timing and outcome of future AB 1054 securitization transactions, the timing and outcome of the potential sale of a minority interest in Pacific Generation to one or more investors to be identified, dividend payments, and equity contributions from PG&E Corporation.

LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 2, Note 15, and 16 of the Notes to the Consolidated Financial Statements in Item 8 that are incorporated by reference herein. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of the proceedings described below and other proceedings may materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

During the year ended December 31, 2022 and through the date of this filing, the Utility has continued to make progress on regulatory and legislative matters.

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In February 2023, the CPUC approved a final decision, adopting without modification the Utility's settlement agreement in its 2020 WMCE proceeding, pursuant to which the Utility will recover a revenue requirement of $1.04 billion. In January 2023, the Utility submitted a partial settlement regarding the 2021 WMCE application pursuant to which the Utility would receive a revenue requirement of $720.7 million. In December 2022, the Utility filed the 2022 WMCE application requesting cost recovery of approximately $1.36 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.29 billion.

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In December 2022, OEIS issued the Utility's 2022 safety certification.

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In December 2022, the CPUC approved a resolution authorizing the Utility's exit from the EOEP.

-

In December 2022, the CPUC issued a final decision in the Utility's 2023 cost of capital proceeding, which sets the Utility's ROE for 2023 at 10%.

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In November 2022, OEIS issued its final decision approving the Utility's 2022 WMP, which the CPUC ratified in December.

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In November 2022, the CPUC issued a final decision in the Utility's 2022 cost of capital proceeding. The decision retains the Utility's cost of capital previously authorized in the 2020 cost of capital proceeding.

-

In September 2022, the Utility filed an application with the CPUC regarding the separation of its non-nuclear generation assets into a stand-alone Utility subsidiary and the potential sale of a minority interest in the newly-formed subsidiary to one or more investors to be identified.

-

In September 2022, the Governor of California signed SB 884, which authorizes and expedites OEIS and CPUC review of a 10-year undergrounding plan.

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In September 2022, the Governor of California signed SB 846, which supports the extension of operations at Diablo Canyon until 2030. In October 2022, the Utility executed a loan agreement with the DWR for up to $1.4 billion. In November, the DOE conditionally selected the Utility to receive funding of up to $1.1 billion as part of the Civil Nuclear Credit Program.

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In August 2022, the CPUC issued a final decision approving the securitization of up to approximately $1.4 billion of fire risk mitigation capital expenditures, and in November 2022, PG&E Recovery Funding LLC issued approximately $983 million aggregate principal amount of Series 2022-A Senior Secured Recovery Bonds. See Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

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In March 2022, the CPUC approved a settlement agreement for the Utility's 2018 CEMA application approving a total revenue requirement of $683 million plus interest for its expenses and capital costs, which is approximately 90% of the Utility's total cost recovery request.

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In February 2022, a CPUC decision finding $7.5 billion of stress test costs eligible for securitization pursuant to SB 901 and a financing order authorizing the issuance of up to $7.5 billion of recovery bonds became final and non-appealable. PG&E Wildfire Recovery Funding LLC issued $3.6 billion aggregate principal amount of Series 2022-A Recovery Bonds in May and $3.9 billion aggregate principal amount of Series 2022-B Recovery Bonds in July. See Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

In February 2022, the Utility served supplemental testimony for its 2023 GRC to reflect the Utility's integrated wildfire mitigation strategy, including the Utility's proposals for the initial phase of undergrounding 10,000 miles of electric distribution powerlines. In September 2022, the Utility submitted testimony updating the revenue requirement to reflect updates for escalation rates and federal tax law and guidance. As amended and updated, the Utility's application requests revenue requirements of $15.82 billion and a weighted-average GRC rate base of $50.41 billion for its 2023 test year. In January 2023, the Utility filed a motion for approval of a settlement agreement for all amounts at issue in the second track of the proceeding, for $183 million in expense and $127 million of capital expenditures. Also in January 2023, the CPUC approved a settlement pursuant to which the Utility's wildfire liability insurance will be entirely based on self-insurance beginning in 2023.

Cost Recovery Proceedings

Periodically, costs arise that could not have been anticipated by the Utility during CPUC GRC proceedings or that have been deliberately excluded from such requests. 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 may also authorize 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, other wildfire prevention-related costs, certain third-party wildfire claims, and insurance costs. While the Utility generally expects such costs to be recoverable, there can be no assurance that the CPUC will authorize the Utility to recover the full amount of its costs.

In recent years, the amount of the costs recorded in these accounts has increased. Because rate recovery may require CPUC authorization for these accounts, there can be a delay between when the Utility incurs costs and when it may recover those costs. As of December 31, 2022, the Utility had recorded an aggregate amount of approximately $6.2 billion in costs for the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, MGMA, and RTBA. Of these costs, approximately $856 million was authorized for recovery and accounted for as current, and $5.3 billion was accounted for as long term as of December 31, 2022. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

If the amount of the costs recorded in these accounts continues to increase or the delay between incurring and recovering costs lengthens, PG&E Corporation and the Utility may incur additional financing costs. If the Utility does not recover the full amount of its recorded costs, the difference between the recorded and recovered amounts would be written off as a non-cash disallowance. Such disallowances could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Except as otherwise noted, the Utility is unable to predict the timing and outcome of the following applications. 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 these applications.

For more information, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8, "Wildfire Mitigation and Catastrophic Events Cost Recovery Applications," and "Catastrophic Event Memorandum Account Application" below.

The Utility's cost recovery proceedings for the costs described above that are pending, have pending appeals, or were completed during the year ended December 31, 2022 are summarized in the following table:

Proceeding

Request

Status

2020 WMCE

Revenue requirement of approximately $1.28 billion

Settlement agreement to recover $1.04 billion of revenue requirement approved February 2023.

2021 WMCE

Revenue requirement of approximately $1.47 billion

Partial settlement agreement to recover $721 million of revenue requirement filed January 2022. Settlement excludes VMBA's $591 million revenue requirement.

2022 WMCE

Revenue requirement of approximately $1.36 billion

Filed December 15, 2022.

2018 CEMA

Revenue requirement of $763 million

Settlement agreement to recover $683 million plus interest approved March 2022.

Wildfire Mitigation and Catastrophic Events Cost Recovery Applications

2020 WMCE Application

On September 30, 2020, the Utility filed an application with the CPUC requesting cost recovery of recorded expenditures related to wildfire mitigation and certain catastrophic events (the "2020 WMCE application"). The recorded expenditures, which excluded amounts disallowed as a result of the CPUC's decision in the OII into 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"), and the 2018 Camp fire, consisted 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 2020 WMCE application cover activities mainly during the years 2017 to 2019 and were incremental to those previously authorized in the Utility's 2017 GRC and other proceedings. The majority of costs addressed in this application reflected work necessary to mitigate wildfire risk and to respond to catastrophic events occurring during the years 2017 to 2019. The Utility's requested revenue included amounts for the FHPMA of $293 million, the FRMMA and the WMPMA of $740 million, and the CEMA of $251 million.

On September 21, 2021, the Utility and certain parties filed a motion with the CPUC seeking approval of a settlement agreement that would resolve all of the issues raised by the settling parties in the 2020 WMCE application. The settlement agreement proposes that the Utility recover a revenue requirement of $1.04 billion. The settlement agreement authorizes the Utility to recover a revenue requirement of $591 million over a 24-month amortization period beginning March 2023, which is in addition to the interim rate relief of $447 million that was approved by an earlier CPUC decision. On February 2, 2023, the CPUC approved a final decision adopting the settlement agreement without modifications.

2021 WMCE Application

On September 16, 2021, the Utility filed an application with the CPUC requesting cost recovery of approximately $1.6 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.47 billion (the "2021 WMCE application"). The costs addressed in this application reflect costs related to wildfire mitigation and certain catastrophic events, as well as implementation of various customer-focused initiatives. These costs were incurred primarily in 2020.

The recorded expenditures consist of $1.4 billion in expenses and $197 million in capital expenditures. The costs addressed in the 2021 WMCE application are incremental to those previously authorized in the Utility's 2017 GRC, 2020 GRC, and other proceedings. The majority of the Utility's proposed revenue requirement would be collected over a two-year period beginning in January 2023.

The Utility's requested revenue requirement includes amounts recorded to the VMBA of $592 million, the CEMA of $535 million, the WMBA of $149 million, and other memorandum accounts. On

November 18, 2021, the Utility filed updates to the application, increasing total costs by $19.4 million. On December 30, 2021, the Utility filed supplemental testimony reducing the cost recovery request of the COVID-19 CEMA costs by $12.2 million. The $12.2 million reduction was a result of costs, such as employee business travel expenses and in-person training costs, that the Utility was able to avoid due to the pandemic.

On January 18, 2023, the Utility, TURN, and Cal Advocates filed a joint motion for approval of a settlement agreement, pursuant to which the Utility would receive a revenue requirement of $720.7 million. The settlement agreement does not address $591.9 million recorded to the VMBA, for which cost recovery will be determined separately by the CPUC.

2022 WMCE Application

On December 15, 2022, the Utility filed an application with the CPUC requesting cost recovery of approximately $1.36 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.29 billion (the "2022 WMCE application"). The costs addressed in this application reflect costs related to wildfire mitigation and certain catastrophic events, as well as implementation of various customer-focused initiatives. These costs were incurred primarily in 2021.

The recorded expenditures consist of $1.2 billion in expenses and $136 million in capital expenditures. The costs addressed in the 2022 WMCE application are incremental to those previously authorized in the Utility's 2020 GRC and other proceedings. In connection with the 2022 WMCE application, the Utility also requested interim rate relief of $1.1 billion to be recovered over 12 months beginning June 1, 2023. The remaining $224 million would be recovered after the CPUC issues a final decision.

The Utility has proposed a schedule that would call for a final decision by the CPUC in December 2023.

Catastrophic Event Memorandum Account Application

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. The Utility has historically sought such costs through standalone CEMA applications. More recently, the Utility has sought to recover CEMA-eligible costs through its WMCE applications.

In addition to the Utility's responsibilities in responding to catastrophic events, in 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. Through 2019, the costs associated with this work were tracked in the CEMA. In the 2020 GRC decision, the CPUC required the Utility to track these costs in the VMBA for the period beginning January 1, 2020.

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as $405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. The Utility filed three revisions to this application, resulting in a total cost recovery request of $763 million.

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, commencing on October 1, 2019.

On March 17, 2022, the CPUC approved a settlement agreement authorizing the Utility to collect a total of $683 million plus interest for the 2018 CEMA application. As noted above, $373 million of the total amount had already been collected in interim rates. The interim rates became final and are no longer subject to refund. The remainder of the authorized revenue requirement will be amortized over a 12-month period, which began on June 1, 2022.

Forward-Looking Rate Cases

The Utility routinely participates in forward-looking rate case applications before the CPUC and the

FERC. Those applications include GRCs, where the revenue required for general operations ("base revenue") of the Utility is assessed and reset. In addition, the Utility is periodically involved in "cost of capital" proceedings to adjust its regulated return on rate base. The Utility's future earnings will depend on the revenue requirements authorized in such rate cases.

Decisions in GRC proceedings have historically been expected prior to the commencement of the period to which the rates would apply. In recent years, decisions in GRC proceedings have been delayed. Delayed decisions may cause the Utility to develop its budgets based on approved revenue requirements and possible outcomes, rather than authorized amounts. When decisions are delayed, the CPUC typically provides rate relief to the Utility effective as of the commencement of the rate case period (not effective as of the date of the delayed decision). Nonetheless, the Utility's spending during the period of the delay may exceed the authorized amount, without an ability for the Utility to seek cost recovery of such excess. If the Utility's spending during the period of the delay is less than the authorized amount, the Utility could be exposed to operational and financial risk associated with the lower level of work achieved compared to that funded by the CPUC.

Except as otherwise noted, the Utility is unable to predict the timing and outcome of the following applications. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected depending on the outcomes of these applications.

The Utility's forward-looking rate cases that are pending, have pending appeals, or were completed during the year ended December 31, 2022 are summarized in the following table:

Rate Case

Request

Status

2023 GRC

Revenue requirement of $15.82 billion for 2023

A decision is scheduled for the third quarter of 2023.

2022 Cost of Capital

Leave cost of capital components at pre-2022 levels for 2022

Final decision issued November 2022, leaving the cost of capital components at pre-2022 levels for 2022. Intervenors filed application for rehearing in December 2022.

2023 Cost of Capital

Increase ROE to 11% and cost of debt to 4.31%

Final decision issued December 2022, adopting a 10% ROE. Intervenor filed application for rehearing in January 2023.

2015 GT&S

Revenue requirement of $416 million related to 2011-2014 capital expenditures subject to audit

Final decision issued July 2022 approving settlement to recover $356 million of revenue requirements.

2023 General Rate Case

On June 30, 2021, the Utility filed its 2023 GRC application with the CPUC ("the Original Application"). The 2023 GRC combined what had historically been separated into the GRC and GT&S rate cases. 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"). 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, gas 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, natural gas and power purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC. In the Original Application, the Utility proposed a series of safety, resiliency, and clean energy investments to further reduce wildfire risk and deliver safe, reliable, and clean energy service.

Between August 2021 and January 2022, the Utility served various updates to its 2023 GRC testimony. On February 25, 2022 and February 28, 2022, the Utility served supplemental testimony for its 2023 GRC to reflect the Utility's integrated wildfire mitigation strategy, including the Utility's proposals for the initial phase of undergrounding 10,000 miles of electric distribution powerlines in high fire risk areas throughout the Utility's service area, the EPSS program, and its EVM program.

On March 10, 2022, the Utility filed an amended application that revised and superseded the revenue requirement request in the Original Application. On September 6, 2022, the Utility submitted testimony updating the revenue requirement request in its 2023 GRC proceeding. The testimony reflected updates for escalation rates and federal tax law and guidance since the filing of the Original Application. On December 9, 2022, the Utility submitted a post-hearing reply brief. In the reply brief, the Utility updated the revenue requirement request due to the wildfire insurance settlement dated October 7, 2022 discussed below, stipulations with the parties regarding several disputed issues, and a reduction to the Utility's forecast for wildfire system hardening mileage targets over the 2023 to 2026 rate case period.

As amended and updated, the Utility's application requests revenue requirements of $15.82 billion and a weighted-average GRC rate base of $50.41 billion for its 2023 test year. The tables below compare the requested revenue requirements and rate base for the GRC period from 2023 through 2026 to those adopted for 2022 in the 2020 GRC and 2019 GT&S proceedings:

(in billions)

2022

(as adopted)

2023

2024

2025

2026

Requested revenue requirement

$

12.21

$

15.82

$

16.74

$

17.18

$

17.43

Requested weighted-average GRC rate base

39.21

50.41

55.39

59.56

63.68

Over the GRC period of 2023 through 2026, the Utility plans to make average annual capital investments of approximately $9.69 billion in gas distribution, transmission and storage, electric distribution, and electric generation infrastructure, and to improve safety, reliability, and customer service.

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On July 22, 2022, the Utility submitted a request for the second track of this proceeding, requesting cost recovery of recorded expenditures related primarily to the safety and reliability of the Utility's gas transmission and storage system incurred from January 2015 to December 2021. The recorded expenditures consist of $206 million in expenses and $129 million in capital expenditures, resulting in a proposed revenue requirement of approximately $241 million, most of which is proposed to be collected over a two-year period beginning August 1, 2023. On January 6, 2023, the Utility and the Public Advocates Office of the CPUC filed a motion for approval of a settlement agreement for all amounts at issue in the second track of the proceeding. In the motion, the parties requested that the CPUC approve $183 million in expense and $127 million of capital expenditures for recovery through rates.

On January 12, 2023, the CPUC approved a settlement agreement among the Utility and two parties to the proceeding pursuant to which the Utility's wildfire liability insurance will be entirely based on self-insurance beginning in 2023. The self-insurance will be funded through CPUC-jurisdictional rates at $400 million for test year 2023 and subsequent years until $1.0 billion of unimpaired self-insurance is reached. If losses are incurred, the settlement agreement contains an adjustment mechanism designed to adjust customer funded self-insurance based on the amount of wildfire related liabilities incurred in the previous year. For 2024, 2025, and 2026, if the estimated claims for wildfire events from the immediately preceding year exceed the amount collected for self-insurance in that same year, the self-insurance amount to be collected in rates during the following year would increase by 50% of the difference between the self-insurance amount collected and estimated claims for events in the immediately preceding year. As a result, the Utility could collect the self-insurance amounts over a longer period than it makes wildfire-related payments. The settlement agreement includes a five percent deductible, capped at a maximum of $50 million, on claims that are incurred each year. The settlement agreement prohibits the Utility from purchasing additional wildfire liability insurance from the commercial insurance market.

The Utility does not seek 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.

The CPUC's schedule indicated a final decision on the first two tracks of this proceeding would be issued in the third quarter of 2023.

Cost of Capital Proceedings

2020 and 2022 Cost of Capital Applications

On December 19, 2019, the CPUC approved a final decision in the 2020 cost of capital application (the "2020 cost of capital application"), maintaining the Utility's ROE at the 2019 level of 10.25% for the three-year period beginning January 1, 2020. The decision maintained the common equity component of the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt for ratemaking) at 52% and reduced its preferred stock component from 1% to 0.5%. The decision also approved the cost of debt requested by the Utility.

On August 23, 2021, the Utility filed an off-cycle 2022 cost of capital application with the CPUC. The Utility also concurrently filed a motion requesting that the revenue requirement for the 2022 cost of capital be recorded in memorandum accounts to be trued-up following a final decision in this proceeding. On October 28, 2021, the CPUC ruled that the Utility was required to comply with the cost of capital mechanism for 2022.

On November 3, 2022, the CPUC issued a final decision, finding that an extraordinary event occurred, and that the cost of capital adjustment mechanism should not be implemented for 2022. The final decision retains the cost of capital for 2022 previously authorized in the 2020 cost of capital proceeding, as adjusted, and closes this proceeding. On December 5, 2022, intervenors filed an application for rehearing. On December 20, 2022, the Utility filed a response to the application for rehearing.

For more information regarding this proceeding, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

2023 Cost of Capital Application

On April 20, 2022, the Utility filed an application with the CPUC requesting that the CPUC authorize the Utility's cost of capital for its electric generation, electric distribution, natural gas distribution, and natural gas transmission and storage rate base beginning on January 1, 2023 (the "2023 cost of capital application").

In its 2023 cost of capital application, the Utility requested that the CPUC approve the Utility's proposed ratemaking capital structure (i.e., the relative weightings of common equity, preferred equity, and debt for ratemaking), ROE, cost of preferred stock, and cost of debt.

On December 19, 2022, the CPUC issued a final decision adopting a new cost of capital. On January 10, 2023, the CPUC issued a decision correcting certain typographical errors in the final decision.

The following table compares the currently authorized capital structure and rates of return with those adopted in the final decision for 2023, as corrected.

2022 authorized by the 2022 Cost of Capital Application

2023 Cost of Capital decision

Cost

Capital structure

Weighted cost

Cost

Capital structure

Weighted cost

Common equity

10.25

%

52.00

%

5.33

%

10.00

%

52.00

%

5.20

%

Preferred stock

5.52

%

0.50

%

0.03

%

5.52

%

0.50

%

0.03

%

Long-term debt

4.17

%

47.50

%

1.98

%

4.31

%

47.50

%

2.05

%

Weighted average cost of capital

100.00

%

7.34

%

100.00

%

7.28

%

For 2023, the Utility expects that the newly-adopted cost of capital will result in revenue requirement decreases of approximately $23 million for electric generation and distribution and $10 million for gas distribution operations, assuming 2022 authorized rate base amounts from the 2020 GRC decision. The revenues for the gas transmission and storage operations will decrease by approximately $7 million, assuming 2022 authorized rate base amounts from the 2019 GT&S decision. Actual revenue requirement changes resulting from the Utility's requested ROE for the period beyond 2022 may differ from the amounts reflected above, pending the outcome of the 2023 GRC.

The 2023 cost of capital application also requested that the CPUC approve an upward adjustment above the three-month commercial paper rate for interest on the Utility's balancing and memorandum accounts to reflect the Utility's actual cost of short-term debt. The Utility requested that the adjustment be set on an annual basis effective January 1 of each year based on the average difference between the three-month commercial paper rate and the Utility's actual cost of short-term debt over the preceding twelve-month period from November through October. The Utility included an illustrative calculation using the period March 2021 to February 2022 with an adjustment to increase the rate by 153 basis points, which would result in an estimated $69 million increase in recovery of short-term financing costs associated with its recent balancing and memorandum account balances. The actual revenue requirement impact of the short-term debt proposal would differ depending on the final adjustment set each year and the recorded balances in the balancing and memorandum accounts. The decision deferred consideration of the proposal to a second phase of the proceeding.

The cost of capital that is approved in this proceeding is expected to be effective until December 31, 2025, unless the cost of capital adjustment mechanism is triggered. (For more information on the cost of capital adjustment mechanism, see Note 16 of the Notes to the Consolidated Financial Statements in Item 8.)

On January 18, 2023, an intervenor filed an application for rehearing of the final decision. On February 2, 2023, the Utility filed a response to the application for rehearing.

2015 Gas Transmission and Storage Rate Case

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 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 million in 2015 to 2022 revenue associated with $512 million of recorded capital expenditures. On July 7, 2021, the Utility filed a joint motion to adopt a settlement agreement reached with the active parties in the proceeding. On July 14, 2022, the CPUC approved a final decision approving the settlement agreement, which resolved all issues in this proceeding and authorized a $356 million revenue requirement for the period of 2015 through 2022. Of this amount, $313 million of revenues for the period 2015 through 2021 will be amortized in rates over 60 months and $43 million associated with 2022 will be amortized in rates over 12 months beginning August 1, 2022. Going forward, the as-yet undepreciated capital plant associated with this application was included in test year 2023 rate base in the Utility's consolidated 2023 GRC.

Transmission Owner Rate Cases

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

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of 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 Ninth Circuit 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 its order denying requests for rehearing that were 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.

On March 17, 2022, the Ninth Circuit Court of Appeals upheld the FERC's order granting the Utility the 50-basis point ROE incentive adder for CAISO participation. The order would extinguish the Utility's refund obligations that might have been required under the TO16 and TO17 rate cases had the Ninth Circuit Court of Appeals not found in the FERC's favor. On May 2, 2022, the CPUC filed a petition for panel rehearing of the order. On May 25, 2022, the Ninth Circuit Court of Appeals issued a decision denying the request for rehearing and the request for a rehearing

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

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.

On October 15, 2020, the FERC issued an order that, 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 FERC Opinion No. 569-A, issued on May 21, 2020.

On December 17, 2020 and June 17, 2021, the FERC issued orders denying requests for rehearing submitted by the Utility and intervenors. In 2021, the Utility filed four appeals. The appeals related to two issues: (1) impact of the Tax Act on TO18 rates in January and February 2018 and (2) aspects of the rehearing order other than the Tax Act. The appeals have been consolidated and are being held in abeyance until the FERC addresses the ROE issue on rehearing.

As a result of an 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 2022 by approximately $416 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 December 31, 2022, the Utility had recorded approximately $258 million to Regulatory assets.

On March 17, 2022, the FERC issued a further order in the TO18 rate case proceeding finding that 9.26% is the just and reasonable base ROE for the Utility. With the incentive component of 50-basis points for the Utility's continuing participation in the CAISO, the resulting ROE would be 9.76%. As a result, the Utility increased its regulatory liability for the potential refund for TO18 by $30 million in 2022. On April 18, 2022, the Utility sought rehearing of the FERC's determination of the base ROE finding. On May 16, 2022 and May 31, 2022, the Utility filed a compliance filing and a refund report describing the adjustments made to the transmission revenue requirement, adjusted rates, and the calculation and mechanism of the refunds. On May 19, 2022, the FERC denied all parties' rehearing requests. The Utility has filed an appeal in the D.C. Circuit Court of Appeals, as have the other parties that sought rehearing. The appeal is being held in abeyance until the FERC issues a substantive order on rehearing on the ROE issue.

Aside from the ultimate outcome of the ROE rehearing request and the common plant allocation, the FERC's orders in the TO18 proceeding are 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. The ROE rehearing request will not impact the TO20 rate case. See "Transmission Owner Rate Case Revenue Subject to Refund" in Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

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

On July 27, 2017, the Utility filed its TO19 rate case with the FERC. On December 20, 2018, the FERC issued an order approving an all-party settlement filed by the Utility. 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 the issuance of a final, non-appealable TO18 decision. On March 17, 2022, the Ninth Circuit Court of Appeals upheld the FERC's order granting the Utility the 50-basis point ROE incentive adder for CAISO participation and eliminating the refund obligation, and so the Utility was not obligated to make a refund to customers based on this matter. See "Transmission Owner Rate Cases for 2015 and 2016" above for a discussion of the incentive adder. As a result of the potential reduction to the TO18 revenue requirement, the Utility increased its regulatory liability for the potential refund for TO19 by $32 million in the first quarter of 2022. On April 18, 2022, the Utility sought rehearing of the FERC's determination of the base ROE finding.

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

On October 1, 2018, the Utility filed its TO20 rate case with the FERC requesting approval of a formula rate for the costs associated with the Utility's electric transmission facilities. On November 30, 2018, the FERC issued an order accepting the Utility's October 2018 filing, subject to hearings and refund, and established May 1, 2019 as the effective date for rate changes. The FERC also ordered that the hearings be held in abeyance pending settlement discussions among the parties.

On March 31, 2020, the Utility filed a partial settlement with the FERC, which the FERC approved on August 17, 2020. On October 15, 2020, the Utility filed a settlement with the FERC resolving all of the remaining issues in the formula rate proceedings, including the Utility's ROE, capital structure, depreciation rates, as well as certain other aspects of the Utility's formula rate. Specifically, the settlement established an all-in ROE of 10.45%; a fixed capital structure of 49.75% common stock, 49.75% debt, and 0.5% preferred stock; and fixed depreciation rates for various categories of transmission facilities (represented by individual FERC accounts). The term of the settlement continues until December 31, 2023 and the Utility will be required to file a replacement rate filing by October 18, 2023 to be effective on January 1, 2024.

On December 30, 2020, the FERC approved the settlement without modification.

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 TO20 rate case.

Under its formula rate, the Utility submits an annual update to the FERC each December for rates to go into effect on January 1 of the following year. Parties have protested the Utility's annual updates, and these protests are pending before the FERC.

Other Regulatory Proceedings

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 operational 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. 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 OIIs 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 fines or penalties may be imposed, or other regulatory actions may be taken.

Vegetation Management

The CPUC placed the Utility into step 1 of the EOEP on April 15, 2021 and imposed additional reporting requirements on the Utility. The CPUC's resolution states that a step 1 triggering event had occurred because the Utility had "made insufficient progress toward approved safety or risk-driven investments related to its electric business." The resolution found that, based on the CPUC's evaluation of the Utility's EVM work in 2020, the Utility was "not sufficiently prioritizing its Enhanced Vegetation Management ("EVM") based on risk" and was "not making risk-driven investments." The resolution also found 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 was 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 addressed the EVM situation that occurred in 2020 and provided a risk-informed EVM work plan for 2021. The Utility was required to update the information contained in the corrective action plan every 90 days, which it did.

On December 1, 2022, the CPUC issued a resolution authorizing the Utility's exit from the EOEP.

Application for Post-Emergence SB 901 Securitization Transaction

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 recover $7.5 billion of 2017 wildfire claims costs through securitization that is designed to be rate neutral to customers through the creation of a corresponding customer credit trust, with the proceeds used to pay or reimburse the Utility for the payment of wildfire claims costs associated with the 2017 Northern California wildfires. Among other uses, as a result of the proposed transaction, the Utility would retire $6.0 billion of Utility debt. 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.

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. and approving a structure for the transaction. As requested, the decision authorized the Utility to establish a customer credit trust funded by PG&E Corporation's shareholders, that will provide a monthly credit to customers that is anticipated to equal the securitized charges such that the securitization is designed to be rate neutral to customers. Subject to retention of the CPUC's existing jurisdiction, the decision adopted a transaction structure comprised of four elements: (1) an initial shareholder contribution of $2.0 billion, $1.0 billion of which was contributed in 2022 and $1.0 billion to be contributed in 2024; (2) up to $7.59 billion of additional contributions funded by certain shareholder tax benefits; (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) sharing with customers 25% of any surplus of shareholder assets in the customer credit trust at the end of the life of the trust.

In addition, 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 finance, using securitization, the $7.5 billion of claims associated with the 2017 Northern California wildfires, which the CPUC subsequently granted on May 11, 2021.

On February 28, 2022, the decision finding $7.5 billion of stress test costs eligible for securitization and the financing order authorizing the issuance of up to $7.5 billion of recovery bonds became final and non-appealable. The financing order authorized the issuance of bonds through the end of 2022. PG&E Wildfire Recovery Funding LLC issued $3.6 billion aggregate principal amount of Series 2022-A Recovery Bonds on May 10, 2022 and $3.9 billion aggregate principal amount of Series 2022-B Recovery Bonds on July 20, 2022. See Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

Application for Second AB 1054 Securitization Transaction

AB 1054 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 has been allocated among the large electric IOUs in accordance with their Wildfire Fund allocation metrics. The Utility's allocation is $3.21 billion. AB 1054 contemplates that such capital expenditures may be financed using a structure that securitizes a dedicated customer charge. Pursuant to an earlier financing order issued by the CPUC authorizing the Utility's initial application for AB 1054 securitization transaction, on November 12, 2021, PG&E Recovery Funding LLC issued approximately $860 million of senior secured recovery bonds. See Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

On March 11, 2022, the Utility filed an application with the CPUC seeking authorization for a second transaction to securitize up to $1.7 billion of fire risk mitigation capital expenditure amounts that have been or would be incurred by the Utility from 2019 through 2022. The $1.7 billion reflected $212 million recorded and $1.16 billion forecasted capital expenditure amounts that were approved by the CPUC in the 2020 GRC and up to $350 million capital expenditure amounts pending in the 2020 WMCE proceeding. On May 4, 2022, the $350 million of capital expenditure amounts were removed because the CPUC extended the schedule in the 2020 WMCE proceeding such that a final decision approving such capital expenditure amounts in that proceeding was no longer expected prior to the issuance of a financing order authorizing the second AB 1054 securitization transaction. The final amount to be securitized would be based on actual recorded 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, would reduce rates on a present-value basis compared to traditional utility financing mechanisms, and authorize the Utility to collect a non-bypassable charge sufficient to pay debt service on the recovery bonds. The application also requested that the CPUC exclude the securitized debt from the Utility's ratemaking capital structure and adjust the Utility's 2020 GRC revenue requirements following the issuance of the recovery bonds.

On August 5, 2022, the CPUC issued a final decision approving the securitization of up to approximately $1.4 billion of fire risk mitigation capital expenditures, which was the amount requested in the application less the $350 million then pending in the 2020 WMCE proceeding.

On November 30, 2022, PG&E Recovery Funding LLC issued approximately $983 million aggregate principal amount of Series 2022-A Senior Secured Recovery Bonds.

2020-2022 Wildfire Mitigation Plan

The Utility's 2022 WMP was submitted on February 25, 2022. The 2022 WMP addressed the Utility's wildfire safety programs and initiatives 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 November 10, 2022, OEIS approved the Utility's 2022 WMP. On December 15, 2022, the CPUC ratified OEIS's approval.

On December 5, 2022, OEIS issued its draft Annual Report on Compliance ("ARC") for the Utility's 2020 WMP. In the draft ARC, OEIS found that the Utility undertook significant efforts to reduce its wildfire risk and, in many instances, achieved its stated objectives and targets but found that the Utility failed to meet targets highly correlated with risk, failed to achieve critical stated objectives, and failed to sufficiently address risk on its system. Consequently, OEIS found the Utility did not substantially comply with the WMP during the 2020 compliance period. The Utility submitted comments on the draft ARC in December 2022. If the OEIS final ARC report maintains the finding that the Utility failed to substantially comply with its 2020 WMP, the Utility may seek judicial review.

If the ARC finds that the Utility did not substantially comply with the WMP during the 2020 compliance period, the CPUC is required to issue penalties for the finding of noncompliance. PG&E Corporation and the Utility cannot reasonably estimate at this time whether they will incur a loss in connection with the ARC or the amount of any such loss, as OEIS has not issued the final ARC and because any penalty issued by CPUC depends upon a number of factors.

Electric Integrated Resource Planning and Related 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 required 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 from 2021 to 2023, of which the Utility is responsible for 716.9 MWs for its bundled customer portion. The decision required that at least 50% of LSEs 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 directed the IOUs to act as the backstop procurement agent for CCAs and energy service providers 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 June 30, 2021, the CPUC issued a mid-term reliability decision to address incremental electric system reliability needs between 2024 and 2026 due to, in part, the pending retirement of once-through-cooling natural gas plants in Southern California and the possible retirement of Diablo Canyon by requiring at least 11,500 MW of additional net qualifying capacity to be procured by LSEs. See "Extension of Diablo Canyon Operations" below. The decision set 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 set the Utility's share of the procurement at 2,302 MW of incremental net qualifying capacity.

On April 21, 2022, the CPUC approved a group of nine long-term RA agreements to meet a portion of the Utility's procurement requirements under the CPUC's mid-term reliability decision. The agreements are each for a term of 15 years and collectively expected to supply 1,598.7 MW of lithium-ion energy storage capacity with some projects expected to be operational in 2023 and others in 2024.

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 allow customer-sited renewable generation to grow sustainably among different types of customers.

On November 10, 2022, the CPUC withdrew a previously-issued PD and issued a new PD. On December 19, 2022, the CPUC issued a final decision. The final decision will reduce the NEM subsidy by, in large part, reducing the bill credits for exported energy to avoided cost levels for new customers interconnecting under the successor tariff established by the final decision. For new non-CARE customers interconnecting under the successor tariff, the subsidy is reduced by about 60% for standalone solar and about 45% for solar-paired storage. The decision will also reduce the subsidy for new commercial customers interconnecting under the successor tariff by about 35%. The decision declined to adopt a charge to recover grid and infrastructure costs for new or existing customers and, instead, defers to the ongoing Demand Flexibility OIR, which is considering income-based fixed charges for all customers. The decision does, however, clarify that charges adopted in the Demand Flexibility OIR will apply to NEM and successor tariff customers. The final decision does not reform the legacy period for existing NEM customers.

On January 18, 2023, intervenors filed an application for rehearing. On February 2, 2023, the Utility filed a response to the application for rehearing.

Application with Pacific Generation LLC for Approval to Transfer Non-Nuclear Generation Assets

On September 28, 2022, the Utility filed an application with the CPUC regarding the separation of the Utility's non-nuclear generation assets into a newly formed, stand-alone Utility subsidiary, Pacific Generation. The application, which was filed jointly with Pacific Generation, seeks to establish Pacific Generation as a separate, rate-regulated utility subject to regulation by the CPUC and contemplates the potential sale of a minority interest in Pacific Generation to one or more investors to be identified. The application proposes that the negotiated transaction documents would be submitted to the CPUC via an advice letter.

On December 13, 2022, the Utility filed applications with a similar request with the FERC and also filed a related application with the FERC requesting the transfer of certain hydro licenses to Pacific Generation.

On January 20, 2023, the CPUC issued a scoping memo pursuant to which a PD would be issued by November 2023.

Self-Reports to the CPUC

The Utility self-reports potential violations of certain requirements to the CPUC. The Utility could face penalties, enforcement actions, or other adverse legal or regulatory consequences for these potential violations, including under the EOEP. The Utility is unable to predict the likelihood and the amount of potential fines or penalties, if any, related to these matters.

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 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. 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.

On October 26, 2022, the Utility notified the CPUC that the Utility's procedure for wood pole replacements did not comply with CPUC requirements for replacement of poles under certain conditions and, accordingly, in some instances, the Utility failed to replace wood poles with safety factors below the required minimum. Among other short- and longer-term corrective measures, the Utility is replacing identified poles on a risk prioritized basis and revising its wood pole replacement procedures in alignment with CPUC requirements. On December 22, 2022, the Utility submitted an update to the CPUC explaining the Utility had identified a population of wood poles that had not received intrusive inspections in accordance with GO 165's deadlines due to legacy issues, which should no longer be an issue due to changes in Utility procedures. In addition to its plan to complete the intrusive tests by September 30, 2023, the Utility is performing an end-to-end assessment of the wood pole test and treat program to proactively identify and address potential issues.

The Utility continues to evaluate whether there are additional failures to comply with GO 95 and 165, beyond those identified in submitted self-reports. The Utility intends to update the CPUC upon completion of its reviews and to address any issues it identifies.

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

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

On June 18, 2019, the CPUC issued a ruling requesting comments from parties on four proposals that it stated may improve the safety culture of PG&E Corporation and the Utility. The four proposals are: separating the Utility into gas and electric utilities (including, as one possibility, sale of the gas assets to a third party); establishing periodic review of the Utility's certificate of convenience and necessity; modifying or eliminating PG&E Corporation's holding company structure; and linking the Utility's rate of return or ROE to safety performance metrics.

On September 4, 2020, the administrative law judge issued a ruling updating case status, which states that the proceeding will remain open as a vehicle to monitor the progress of the Utility in improving its safety culture and to address any relevant issues that arise, with the CPUC's consultant continuing in a monitoring role. The ruling states that additional issues may be raised in the proceedings by parties or the CPUC.

Extension of Diablo Canyon Operations

On September 2, 2022, the Governor of California signed SB 846, which supports the extension of operations at Diablo Canyon through no later than 2030, with the potential for an earlier retirement date. Under the legislation, the Utility would continue to operate Diablo Canyon on behalf of all CPUC-jurisdictional LSEs, and all customers of those LSEs would be responsible for the cost of extended operations. Additionally, the State of California has authorized a loan of up to $1.4 billion pursuant to SB 846 to the Utility from the DWR to support the extension of plant operations, which is in addition to the amount discussed in "Assembly Bill 180", below. SB 846 further directs the Utility to take steps to secure funds from the DOE's Civil Nuclear Credit Program, and any other potentially available federal funding, to repay the loan. The loan may be forgiven under certain circumstances. On October 18, 2022, the Utility executed the loan agreement with the DWR.

On September 2, 2022, the Utility applied for federal funding through the DOE's Civil Nuclear Credit Program. On November 17, 2022, the DOE conditionally selected the Utility to receive funding of up to $1.1 billion as part of the program. Final terms are subject to negotiation and finalization by the DOE. SB 846 provides that within 180 days of the filing of the DOE application, the CEC, in consultation with the CAISO and the CPUC, shall make a determination in a public process of whether the state's electricity forecasts for the calendar years from 2024 through 2030 show potential for reliability deficiencies if Diablo Canyon operations are not extended beyond 2025 and whether extending operations of Diablo Canyon until 2030 is prudent to ensure reliability in light of any potential for supply deficiency. During the quarter ended December 31, 2022, the Utility adjusted the ARO to reflect extended operations of Diablo Canyon through 2030. However, the Utility's ARO could be materially impacted if the Utility does not receive the required federal and state licenses, permits, and approvals.

During the period prior to extended operations, the bill authorizes a monthly performance-based disbursement equal to $7 for each MWh generated by Diablo Canyon. The performance-based disbursement will be paid from the loan proceeds authorized by SB 846 and is contingent upon the Utility's ongoing pursuit of extension of the operating period and continued safe and reliable Diablo Canyon operations. The performance-based disbursement cannot be realized as shareholder profits or paid out as dividends.

During the period of extended operations and in lieu of the traditional rate-based return on investment, the bill provides for a fixed payment of $50 million, in 2022 dollars, for each of Diablo Canyon's Unit 1 and Unit 2 for each year of extended operations to be recovered from customers of all CPUC-jurisdictional LSEs, which is potentially subject to adjustment downward in the event of extended unplanned outages. In addition, the bill authorizes a volumetric payment totaling $13, in

2022 dollars, for each MWh generated by Diablo Canyon during the period of extended operations, with the first half recovered from all CPUC-jurisdictional LSEs and the second half from customers in the Utility's service area. The amount of the fixed and volumetric payments will be adjusted annually by the CPUC using CPUC-approved escalation methodologies and adjustment factors. The volumetric payment cannot be realized as shareholder profits or paid out as dividends, to the extent it is not needed for Diablo Canyon. The legislation includes language that limits use of the volumetric payment to investments in the system and for customers that address critical state priorities.

The CPUC has initiated a rulemaking proceeding in January 2023 to develop a new mechanism to recover costs from customers of all CPUC-jurisdictional LSEs for the continued operation of Diablo Canyon and to address other issues associated with continued operation, including cost responsibility if Diablo Canyon is unable to operate. The legislation also established a $300 million Liquidated Damages Balancing Account ("LDBA") to be funded over time by all CPUC-jurisdictional customers. The LDBA provides a source for paying for replacement power costs, if incurred, due to unplanned outages at Diablo Canyon as a result of the Utility's failure to meet the CPUC's reasonable-manager standard.

The key remaining steps to continued operations include NRC license renewal and approval from California state agencies. If either is not received, the Utility would retire Unit 1 in 2024 and Unit 2 in 2025 as previously approved by the CPUC. On October 31, 2022, the Utility requested that the NRC resume its review of a license renewal application the Utility voluntarily withdrew and terminated in 2018 or else grant an exemption to permit operations to continue at Diablo Canyon after the expiration of each of its current operating licenses and until the NRC completes its review of the license renewal application. On January 24, 2023, the NRC staff declined to resume its review of the previously-withdrawn application and directed the Utility to submit a new application for license renewal, which the Utility expects to do by the end of 2023. The NRC staff has stated that it will provide a response to the Utility's request for an exemption in March 2023. Consistent with SB

846, the CPUC, the CEC, California State Lands Commission, California Coastal Commission, and other state agencies will need to determine that extended operations represent an appropriate path to meet California's reliability, affordability, and environmental goals.

LEGISLATIVE AND REGULATORY INITIATIVES

Assembly Bill 180

On June 30, 2022, the Governor of California signed AB 180, which authorized the DWR to use up to $75 million to support contracts with the owners of electric generating facilities pending retirement, such as Diablo Canyon, to fund, reimburse or compensate the owner for any costs, expenses or financial commitments incurred to retain the future availability of such generating facilities pending further legislation.

Assembly Bill 205

On June 30, 2022, the Governor of California signed AB 205, which included authorization for additional incremental CAPP funding of $958 million for California IOUs. The Utility received approximately $200 million in November 2022 to reduce the amounts owed by customer accounts in arrears. The amount of funding was determined by the California Department of Community Services and Development, which is the agency responsible for administering the CAPP.

Senate Bill

846

On September 2, 2022, the Governor of California signed SB 846, which supports the extension of operations at Diablo Canyon through no later than 2030, with the potential for an earlier retirement date. For more information, see "Extension of Diablo Canyon Operations" above.

Senate Bill 884

On September 30, 2022, the Governor of California signed SB 884, which authorizes and expedites OEIS and CPUC review of a 10-year undergrounding plan. Under SB 884, large electrical corporations may submit 10-year plans for undergrounding distribution infrastructure in Tier 2 or 3 HFTDs or rebuild areas to OEIS. The plan must include an evaluation of project costs, projected economic benefits over the life of the assets, and any cost-containment assumptions, including the economies of scale necessary to reduce wildfire risk and mitigation costs and establish a sustainable supply chain. OEIS will have up to nine months to review and approve or deny the plan, and then the CPUC will have up to nine months to review and approve or deny the plan, including its costs.

Inflation Reduction Act

On August 16, 2022, the President of the United States signed the Inflation Reduction Act. The Inflation Reduction Act includes a 15% corporate alternative minimum tax ("CAMT") on the adjusted financial statement income ("AFSI") of corporations with average AFSI exceeding $1.0 billion over a three-year period, effective January 1, 2023. The law also extends and modifies existing tax credits and creates new tax credits for renewable and clean energy sources. Many aspects of the Inflation Reduction Act, including the CAMT, remain uncertain and the U.S. Department of the Treasury and the Internal Revenue Service have been granted broad authority to enact regulations implementing its provisions. Depending on the guidance issued, PG&E Corporation and the Utility's federal income tax liability could increase substantially. PG&E Corporation and the Utility continue to evaluate the impact of the law and its potential implications.

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 substances; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. See Item 1A. Risk Factors, "Environmental Regulation" in Item 1. and "Environmental Remediation Contingencies" in Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit. The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes.

Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices do not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs in its GRC through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $3 million and $5 million at December 31, 2022 and 2021, respectively. See Note 11 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2022 and 2021, if interest rates changed by one percent for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the pre-tax impact on net income over the next 12 months would be $54 million and $76 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. See Note 5 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates.

Energy Procurement Credit Risk

The Utility conducts business with counterparties mainly in the energy industry to purchase electricity or gas and related services, including the CAISO market, other California IOUs, municipal utilities, energy trading companies, pipelines, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas and related services, then the Utility may find it necessary to procure electricity or gas at current market prices or seek alternate services, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security. Security may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Security or performance assurance may be required from the Utility or counterparties when current net receivables or payables and exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties:

Exposure

(1)

(in millions)

Number of

Wholesale

Customers or

Counterparties

>10%

Net Credit

Exposure to

Wholesale

Customers or

Counterparties

>10%

(in millions)

December 31, 2022

$

814

1

$

162

December 31, 2021

$

570

1

$

63

(1)

Exposure is the positive exposure maximum that equals mark-to-market value on physically and financially settled contracts, plus net receivables (payables) where netting is contractually allowed minus collateral posted by counterparties and held by the Utility plus collateral posted by the Utility and held by the counterparties. For purposes of this table, parental guarantees are not included as part of the calculation. Exposure amounts reported above do not include adjustments for time value or liquidity.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting estimates 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 estimates and their key characteristics are outlined below.

Contributions to the Wildfire Fund

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 DWR 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 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 through rates. 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 area classified as HFTDs 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 Emergence 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. The other large electric IOUs made their initial contributions to the Wildfire Fund in September 2019. On December 30, 2021 and 2022, the Utility made its third and fourth annual contributions of $193 million each to the Wildfire Fund. As of December 31, 2022, PG&E Corporation and the Utility have six remaining annual contributions of $193 million (based on the current Wildfire Fund allocation metric). PG&E Corporation and the Utility account for contributions to the Wildfire Fund by capitalizing an asset, amortizing to periods ratably based on an estimated period of coverage, and incrementally adjusting for accelerated amortization as the level of coverage declines, as further described below.

As of December 31, 2022, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $935 million in Other non-current liabilities, $460 million in current assets - Wildfire Fund asset, and $4.8 billion in non-current assets - Wildfire Fund asset in the Consolidated Balance Sheets. During the years ended December 31, 2022 and 2021, the Utility recorded amortization and accretion expense of $477 million and $517 million, respectively. The amortization of the asset, accretion of the liability, and acceleration of the amortization of the asset is reflected in Wildfire Fund expense in the Consolidated Statements of Income. Expected contributions recorded in Wildfire Fund asset on the Consolidated Balance Sheets are discounted to the present value using the 10-year U.S. 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. Initial use of five years of historical data, with average annual statewide claims or settlements of approximately $6.5 billion versus 12 years of historical data, with average annual statewide claims or settlements of approximately $2.9 billion, would have resulted in a six year amortization period. As of December 31, 2022, a 5% change to the assumption around current and future mitigation effort effectiveness would increase the amortization period by five years assuming greater effectiveness and would decrease the amortization period by four years assuming less effectiveness.

Other assumptions used to estimate the useful life include the estimated cost of wildfires caused by participating electric utilities, the amount at which wildfire claims would be settled, the likely adjudication of the CPUC in cases of electric utility-caused wildfires and determination of any amounts required to be reimbursed to the Wildfire Fund, 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 participating 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 and 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 assess the Wildfire Fund asset for acceleration of the amortization of the asset 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 acceleration of the amortization of the asset 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 area. There were fires in the Utility's and other participating utilities' services territories since July 12, 2019, including fires for which the cause is unknown, which may in the future be determined to be covered by the Wildfire Fund. As of December 31, 2022, PG&E Corporation and the Utility recorded $175 million in Other noncurrent assets for Wildfire Fund receivables related to the 2021 Dixie fire. PG&E Corporation and the Utility recorded $6 million and $43 million of accelerated amortization, reflected in Wildfire Fund expense for the years ended December 31, 2022 and 2021, respectively.

For more information, see "Contributions to the Wildfire Fund Established Pursuant to AB 1054" in Note 3 and "Wildfire Fund under AB 1054" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Loss Contingencies

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

Wildfire-Related Liabilities

PG&E Corporation and the Utility are subject to potential liabilities related to wildfires. PG&E Corporation and the Utility record a wildfire-related liability when they determine that a loss is probable and they can reasonably estimate the loss or a range of losses. The provision is based on the lower end of the range, unless an amount within the range is a better estimate than any other amount.

Potential liabilities related to wildfires depend on various factors, including negotiations and settlements or the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties or fines that may be imposed by governmental entities. There are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation or the Utility. For example, the Utility's wildfire-related accruals have changed in the past as new facts and information became available to the Utility, including the availability of new evidence and additional information about the scope and nature of damages.

The process for estimating wildfire-related liabilities 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. See Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Enforcement and Litigation Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly, and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. Actual results may differ materially from these estimates and assumptions. See Note 15 and Note 16 of the Notes to the Consolidated Financial Statements in Item 8.

Loss Recoveries

PG&E Corporation and the Utility have recovery mechanisms available for wildfire liabilities including from insurance, through rates, and from the Wildfire Fund. The Utility has liability insurance from various insurers, which provides coverage for third-party claims. PG&E Corporation and the Utility record a receivable for a recovery when it is deemed probable that recovery of a recorded loss will occur and they can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Loss recoveries are reviewed quarterly, and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with similar events, conversations with the Wildfire Fund administrators, the CPUC and FERC, and other information and events pertaining to a particular matter. See "Loss Recoveries" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental Remediation Liabilities

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former MGP sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has a program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

As of December 31, 2022 and 2021, the Utility's accruals for undiscounted gross environmental liabilities were $1.3 billion each. The Utility's undiscounted future costs could increase to as much as $2.3 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

Regulatory Accounting

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. Despite the ongoing losses related to wildfires (see Note 15 of the Notes to the Consolidated Financial Statements in Item 8), there is no actual or anticipated change in the cost-of-service regulation of the Utility's operations. Therefore, the Utility continues to apply the accounting ASC 980,

Regulated Operations

. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 3 as well as Note 4 of the Notes to the Consolidated Financial Statements in Item 8. As of December 31, 2022, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $20.0 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $20.4 billion.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. If regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

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A portion of the Utility's regulatory asset balances relate to items which could not be anticipated by the Utility during CPUC GRC rate requests resulting from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account, and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. These accounts, which include the CEMA, WEMA, 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. In addition, the CPPMA and RUBA accounts track costs incurred to implement the CPUC's Emergency Authorization and Order Directing Utilities to Implement Emergency Customer Protections to Support California Customers During the COVID-19 pandemic. While the Utility generally believes such costs are recoverable, rate recovery requires CPUC authorization in separate proceedings or through a GRC. For more information, see "Regulatory Matters - Application for Recovery of Costs Recorded in the Wildfire Expense Memorandum Account" and "Regulatory Matters - Catastrophic Event Memorandum Accounts and Applications" above.

Additionally, SB 901 provides a mechanism for the CPUC to potentially allow recovery in future rates, through a securitization mechanism, of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the CHT. The Utility must evaluate the likelihood of recovery in future rates each period. In 2022, PG&E Corporation and the Utility recorded a regulatory asset associated with SB 901. As of December 31, 2022, the SB 901 regulatory asset was approximately $5.4 billion.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

Asset Retirement Obligations

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. See Notes 3 and 4 of the Notes to the Consolidated Financial Statements in Item 8.

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2022, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was approximately $5.9 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets.

Pension and Other Postretirement Benefit Plans

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences between actuarial assumptions and actual plan results. These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP, and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery through rates. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate, and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses. See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2023 was 6.5%, gradually decreasing to the ultimate trend rate of approximately 4.5% in 2031 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were projected based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the Utility's defined benefit pension plan, the assumed return of 6.1% compares to a ten-year actual return of 5.8%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 848 Aa-grade non-callable bonds at December 31, 2022. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

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

(in millions)

Increase

(Decrease) in

Assumption

Increase in 2022

Pension

Costs

Increase in Projected

Benefit Obligation at

December 31, 2022

Discount rate

(0.50)

%

$

5

$

1,038

Rate of return on plan assets

(0.50)

%

108

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Rate of increase in compensation

0.50

%

44

207

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)

Increase

(Decrease) in

Assumption

Increase in 2022

Other Postretirement

Benefit Costs

Increase in Accumulated

Benefit Obligation at

December 31, 2022

Health care cost trend rate

0.50

%

$

8

$

38

Discount rate

(0.50)

%

11

81

Rate of return on plan assets

(0.50)

%

15

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NEW ACCOUNTING PRONOUNCEMENTS

See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

Section: Item7a

>ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 11: Derivatives and Note 12: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

Metadata

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CUSIP6: 69331C

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