

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

or

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

Commission file number: 1-9743

EOG RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

47-0684736
(I.R.S. Employer
Identification No.)

1111 Bagby, Sky Lobby 2, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: 713-651-7000

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

<u>Title of each class</u>	<u>Trading Symbol(s)</u>	<u>Name of each exchange on which registered</u>
Common Stock, par value \$0.01 per share	EOG	New York Stock Exchange

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

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐
Smaller reporting company ☐ Emerging growth company ☐

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2021: \$48,608 million.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value \$0.01 per share, 585,419,164 shares outstanding as of February 11, 2022.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2022 Annual Meeting of Stockholders, to be filed within 120 days after December 31, 2021, are incorporated by reference into Part III of this report.

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PART I

ITEM 1. *Business*

General

EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively, EOG), explores for, develops, produces and markets crude oil, natural gas liquids (NGLs) and natural gas primarily in major producing basins in the United States of America (United States or U.S.), The Republic of Trinidad and Tobago (Trinidad) and, from time to time, select other international areas. EOG's principal producing areas are further described in "Exploration and Production" below. EOG's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports (including related exhibits and supplemental schedules) filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (as amended) are made available, free of charge, through EOG's website, as soon as reasonably practicable after such reports have been filed with, or furnished to, the United States Securities and Exchange Commission (SEC). EOG's website address is www.eogresources.com. Information on our website is not incorporated by reference into, and does not constitute a part of, this report.

At December 31, 2021, EOG's total estimated net proved reserves were 3,747 million barrels of oil equivalent (MMBoe), of which 1,548 million barrels (MMBbl) were crude oil and condensate reserves, 829 MMBbl were NGLs reserves and 8,222 billion cubic feet (Bcf), or 1,370 MMBoe, were natural gas reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 99% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States and 1% in Trinidad. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet (Mcf) of natural gas.

EOG's operations are all crude oil and natural gas exploration and production related. For information regarding the risks associated with EOG's domestic and foreign operations, see ITEM 1A, Risk Factors.

EOG's business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. Pursuant to this strategy, each prospective drilling location is evaluated by its estimated rate of return. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term growth in shareholder value and maintain a strong balance sheet. EOG is focused on innovation and cost-effective utilization of advanced technology associated with three-dimensional seismic and microseismic data, the development of reservoir simulation models and the use of improved drilling equipment and completion technologies for horizontal drilling and formation evaluation. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks and costs associated with all aspects of oil and gas exploration, development and exploitation. EOG implements its strategy primarily by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure, coupled with efficient and safe operations and robust environmental stewardship practices and performance, is integral in the implementation of EOG's strategy.

With respect to information on EOG's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by EOG's working interest in the wells or acreage.

Exploration and Production

United States Operations

EOG's operations are located in most of the productive basins in the United States with a focus on crude oil and, to a lesser extent, liquids-rich natural gas plays.

At December 31, 2021, on a crude oil equivalent basis, 42% of EOG's net proved reserves in the United States were crude oil and condensate, 22% were NGLs and 36% were natural gas. The majority of these reserves are in long-lived fields with well-established production characteristics. EOG believes that opportunities exist to increase production through continued development in and around many of these fields and through the utilization of applicable technologies. EOG also maintains an active exploration program designed to extend fields and add new trends and resource plays to its already broad portfolio.

The following is a summary of wellhead volume statistics and net well completions for the year ended December 31, 2021, total net acres at December 31, 2021, and expected net well completions planned for 2022 for certain areas of EOG's United States operations.

Area of Operation	2021				2022	
	Crude Oil & Condensate Volumes (MBbld) ⁽¹⁾	Natural Gas Liquids Volumes (MBbld) ⁽¹⁾	Natural Gas Volumes (MMcfd) ⁽¹⁾	Total Net Acres (in thousands)	Net Well Completions	Expected Net Well Completions
Delaware Basin	231.1	84.6	651	395	288	375
South Texas	149.5	29.3	273	1,131	166	125
Rocky Mountain	50.3	16.9	182	1,037	50	<50
Other Areas	12.5	13.7	104	1,130	12	20
Total	443.4	144.5	1,210	3,693	516	520

(1) Thousand barrels per day or million cubic feet per day, as applicable.

In the Delaware Basin, EOG completed 288 net wells during 2021, primarily in the Delaware Basin Wolfcamp, Bone Spring and Leonard plays. The Delaware Basin consists of approximately 4,800 feet of oil rich stacked pay potential offering EOG multiple co-development opportunities throughout its 395,000 net acre position.

In the Delaware Basin Wolfcamp play, EOG has completed 189 net wells in 2021. Continued improvement and excellent results in the Delaware Basin Wolfcamp program were supported by optimized well spacing and co-development, enhanced well completions, precision drilling and continued cost reductions. In 2022, the Delaware Basin Wolfcamp play will continue to be a primary area of focus.

In the Bone Spring play, EOG has three main sub-plays: the First, Second and Third Bone Spring. In 2021, EOG completed 79 total net Bone Spring wells within the three sub-plays. Of the three sub-plays, the Second Bone Spring had the majority of the activity in 2021 with EOG completing 63 net wells. The Bone Spring play continues to be an integral part of EOG's Delaware Basin plans and portfolio.

In the Leonard play, EOG maintained its development plan with 20 net wells completed in 2021. EOG has tested co-development of up to three Leonard zones simultaneously, and expects the Leonard play to become a more active part of EOG's program in the next several years.

Activity in 2022 will remain focused on the Delaware Basin Wolfcamp, Bone Spring, and Leonard plays, where EOG expects to complete approximately 375 net wells.

The South Texas area includes our Eagle Ford oil play and our Dorado gas play. EOG holds approximately 516,000 total net acres in the prolific oil window of the Eagle Ford oil play and approximately 160,000 net acres in the Dorado gas play. In the Dorado gas play, EOG has continued to delineate the Eagle Ford and Austin Chalk formations with excellent results. In 2021, EOG completed 155 net Eagle Ford oil play wells, and 11 net wells in the Dorado gas play. In 2022, EOG expects to complete approximately 95 net Eagle Ford oil play wells and 30 net Dorado wells.

Activity in the Rocky Mountain area in 2021 was focused on the Wyoming Powder River Basin. In the Powder River Basin, EOG operated a two-rig program and completed 45 net wells in the Niobrara, Mowry, Turner and Parkman formations. In addition, key infrastructure was added in order to lower operating costs and increase price realizations going forward. In the DJ Basin, EOG drilled and completed one net well in the Codell formation. In the Williston Basin, EOG completed four net wells in the Bakken and Three Forks formations. Activity in both the DJ and Williston Basins is expected to be minimal in 2022 as development remains focused on the Powder River Basin where EOG plans to complete approximately 40 net wells.

Operations Outside the United States

EOG has operations offshore Trinidad and is making preparations to drill offshore Australia, as well as evaluating additional exploration, development and exploitation opportunities in these and other select international areas. In addition, EOG is in the process of exiting Block 36 and Block 49 in the Sultanate of Oman (Oman) and is executing an abandonment and reclamation program in Canada. EOG sold its operations in the China Sichuan Basin (China) in the second quarter of 2021.

Trinidad. EOG, through its subsidiaries, including EOG Resources Trinidad Limited, holds interests in (i) the exploration and production licenses covering the South East Coast Consortium (SECC) Block, Pelican and Banyan Fields, Sercan Area and each of their related facilities and the Ska, Mento, Reggae and deep Teak, Saaman and Poui Areas, all of which are offshore Trinidad; and (ii) a production sharing contract with the Government of Trinidad and Tobago for each of the Modified U(a), Modified U(b) and 4(a) Blocks.

Several fields in the SECC, Modified U(a), Modified U(b) and 4(a) Blocks, Banyan Field and Sercan Area have been developed and are producing natural gas and crude oil and condensate.

In March 2021, EOG signed a farmout agreement with Heritage Petroleum Company Limited (Heritage), which allows EOG to earn a 65% working interest in a portion of the contract area (EOG Area) governed by the Trinidad Northern Area License. The EOG Area is located offshore the southwest coast of Trinidad.

In 2021, EOG's net production averaged approximately 217 MMcfd of natural gas and approximately 1.5 MBbld of crude oil and condensate. In 2021, EOG made progress on the design and fabrication of a platform and related facilities for its previously announced discovery in the Modified U(a) Block.

In 2022, EOG expects to drill one net exploratory well in the EOG Area in addition to three development wells and one exploratory well in the Modified U(a) Block.

Australia. On April 22, 2021, a subsidiary of EOG entered into a purchase and sale agreement to acquire a 100% interest in the WA-488-P Block, located offshore Western Australia. On November 19, 2021, the petroleum exploration permit for that block was transferred to that subsidiary.

In 2022, EOG will continue preparing for the drilling of an exploration well which is expected to commence in 2023.

Oman. EOG, through its subsidiaries, holds interests in Exploration and Production Sharing Agreements in Block 36 and Block 49 located in Oman.

In 2021, EOG's partner in Block 49 completed the drilling and testing of one net exploratory well, which was determined to be a dry hole. EOG notified its partner and the Ministry of Energy and Minerals of its intention to withdraw from Block 49. Additionally, EOG drilled two exploratory wells and completed one exploratory well in Block 36. There was a discovery of natural gas in Block 36, but the well results did not yield sufficient projected returns for EOG to move forward with the project. In 2022, EOG expects to exit Block 36 in Oman.

China. In May 2021, EOG completed the sale of all of its interest in EOG Resources China Limited. EOG no longer has any operations or assets in China. EOG's net production averaged approximately 25 MMcfd of natural gas prior to the sale.

Canada. In March 2020, EOG began the process of exiting its Canada operations in the Horn River area in Northeast British Columbia.

Marketing

In 2021, EOG continued its diversified approach to marketing its wellhead crude oil and condensate production. The majority of EOG's United States wellhead crude oil and condensate production was transported by pipeline to downstream markets with the remainder sold into local markets. Major U.S. sales areas accessed by EOG were at various locations along the U.S. Gulf Coast, including Houston and Corpus Christi, Texas; Cushing, Oklahoma; the Permian Basin and the Midwest. In 2021, EOG also sold crude oil at the Houston Ship Channel and the Port of Corpus Christi for export to foreign destinations. In each case, the price received was based on market prices at that specific sales point or based on the price index applicable for that location. In 2022, the pricing mechanism for such production is expected to remain the same. At December 31, 2021, EOG was committed to deliver to multiple parties fixed quantities of crude oil of 16 MMBbls in 2022, 7 MMBbls in 2023, 7 MMBbls in 2024, and 1 MMBbls in 2025, all of which is expected to be sourced from future production of available reserves.

In 2021, EOG processed certain of its United States wellhead natural gas production, either at EOG-owned facilities or at third-party facilities, extracting NGLs. NGLs were sold at prevailing market prices, into either local markets or downstream locations. In certain instances, EOG exchanged its NGL production for purity products received downstream, which were sold at prevailing market prices. In 2022, such pricing mechanisms are expected to remain the same. In 2021, EOG also sold purity products at the Houston Ship Channel for export to foreign destinations. In each case, the price received was based on market prices at that specific sales point or based on the price index applicable for that location. In 2022, the pricing mechanism for such production is expected to remain the same. At December 31, 2021, EOG was not committed to deliver fixed quantities of NGLs in 2022.

In 2021, consistent with its diversified marketing strategy, the majority of EOG's United States wellhead natural gas production was transported by pipeline to various locations, including Katy, Texas; East Texas; the Agua Dulce Hub in South Texas; the Cheyenne Hub in Weld County, Colorado; Southern California; and Chicago, Illinois. Remaining natural gas production was sold into local markets. In each case, pricing was based on the spot market price at the ultimate sales point. In 2022, the pricing mechanism for such production is expected to remain the same. Additionally, EOG sells natural gas to a liquefaction facility near Corpus Christi, Texas, and receives pricing based on the Platts Japan Korea Marker. At December 31, 2021, EOG was committed to deliver to multiple parties fixed quantities of natural gas of 223 Bcf in 2022, 190 Bcf in 2023, 150 Bcf in 2024, 138 Bcf in 2025, 195 Bcf in 2026 and 1,459 Bcf thereafter, all of which is expected to be sourced from future production of available reserves.

In 2021, natural gas volumes from Trinidad were sold under a fixed price contract ending in 2026. The pricing mechanism for production in Trinidad is expected to remain the same in 2022.

Through May 2021, all wellhead natural gas volumes from China were sold at regulated prices based on the purchaser's pipeline sales volumes to various local market segments.

In certain instances, EOG purchases and sells third-party crude oil and natural gas in order to balance firm capacity at third-party facilities with production in certain areas and to utilize excess capacity at EOG-owned facilities.

During 2021, two purchasers accounted for more than 10% of EOG's total wellhead crude oil and condensate, NGLs and natural gas revenues and gathering, processing and marketing revenues. The two purchasers are in the crude oil refining industry. EOG does not believe that the loss of any single purchaser would have a materially adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of, and average prices for, crude oil and condensate, NGLs and natural gas. The table also presents crude oil equivalent volumes which are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 Mcf of natural gas for each of the years ended December 31, 2021, 2020 and 2019. See ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations, for wellhead volumes on a per-day basis.

Year Ended December 31	2021	2020	2019
Crude Oil and Condensate Volumes (MMBbl) ⁽¹⁾			
United States:			
Eagle Ford Oil Play	51.8	54.6	68.3
Delaware Basin	84.3	67.0	63.4
Other	25.7	27.8	34.6
United States	161.8	149.4	166.3
Trinidad	0.5	0.4	0.2
Other International ⁽²⁾	—	—	0.1
Total	162.3	149.8	166.6
Natural Gas Liquids Volumes (MMBbl) ⁽¹⁾			
United States:			
Eagle Ford Oil Play	9.0	9.7	10.7
Delaware Basin	30.9	27.7	23.5
Other	12.8	12.4	14.7
United States	52.7	49.8	48.9
Other International ⁽²⁾	—	—	—
Total	52.7	49.8	48.9
Natural Gas Volumes (Bcf) ⁽¹⁾			
United States:			
Eagle Ford Oil Play	55	53	53
Delaware Basin	238	168	147
Other	149	160	190
United States	442	381	390
Trinidad	79	66	95
Other International ⁽²⁾	3	11	14
Total	524	458	499
Crude Oil Equivalent Volumes (MMBoe) ⁽³⁾			
United States:			
Eagle Ford Oil Play	70.0	73.1	87.8
Delaware Basin	154.9	122.7	111.4
Other	63.3	66.9	81.0
United States	288.2	262.7	280.2
Trinidad	13.7	11.4	16.0
Other International ⁽²⁾	0.6	1.8	2.4
Total	302.5	275.9	298.6

Year Ended December 31	2021	2020	2019
Average Crude Oil and Condensate Prices (\$/Bbl) ⁽⁴⁾			
United States	\$ 68.54	\$ 38.65	\$ 57.74
Trinidad	56.26	30.20	47.16
Other International ⁽²⁾	42.36	43.08	57.40
Composite	68.50	38.63	57.72
Average Natural Gas Liquids Prices (\$/Bbl) ⁽⁴⁾			
United States	\$ 34.35	\$ 13.41	\$ 16.03
Other International ⁽²⁾	—	—	—
Composite	34.35	13.41	16.03
Average Natural Gas Prices (\$/Mcf) ⁽⁴⁾			
United States	\$ 4.88	\$ 1.61	\$ 2.22
Trinidad	3.40	2.57	2.72
Other International ⁽²⁾	5.67	4.66	4.44
Composite	4.66	1.83	2.38

(1) Million barrels or billion cubic feet, as applicable.

(2) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

(3) Million barrels of oil equivalent; includes crude oil and condensate, NGLs and natural gas.

(4) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

Human Capital Management

As of December 31, 2021, EOG employed approximately 2,800 persons, including foreign national employees. EOG's approach to human capital management includes oversight by the Board of Directors (Board) and the Compensation and Human Resources Committee of the Board and focuses on various areas, including the following:

Culture; Recruiting; Retention. EOG's culture is key to its sustainable success. By providing employees with a quality environment in which to work, and by maintaining a consistent college recruiting and internship program, EOG is able to attract and retain some of the industry's best and brightest. To help assess the effectiveness of its approach to human capital management, EOG conducts an annual employee engagement survey. Based on the results of the survey, EOG has received "top workplace" recognition in various office locations.

Compensation, Benefits, Health & Wellness. EOG places a high level of importance on attracting and retaining talent, by providing competitive salaries, bonuses and a subsidized, comprehensive benefits package. EOG also offers a holistic wellness program, a matching gifts program, a flexible work schedule, paid family care leave, paid leave for illness or injury and an employee assistance program to support the mental well-being of employees and their dependents. In addition, with new-hire stock grants, an annual stock grant program and an employee stock purchase plan, every employee has the opportunity to be a participant in EOG's success.

COVID-19 Pandemic. In 2020, in response to the COVID-19 pandemic, EOG focused on keeping its employees and their families safe, including providing technology and support to employees to enable them to not only work safely and productively from the office or at home, but also to remain engaged and connected across the company. In 2021, EOG continued to provide such technology and support and remained focused on the safety of its employees, reopening its offices and worksites in a phased approach and instituting additional practices and protocols, including those related to social distancing, mask wearing and symptom screening.

Training and Development. EOG focuses on developing its employees for meaningful career opportunities, including promotion into supervisory and management positions and enhanced compensation opportunities. EOG provides training in leadership, management skills, communication, team effectiveness, technical skills and use of EOG systems and applications. EOG's leadership training is focused on providing continuity of leadership at EOG by further developing the skills needed to lead a multi-disciplined, diverse and decentralized workforce. In addition, EOG holds several internal technical conferences each year designed to share best practices and technical advances across the company, including safety and environmental topics. EOG also offers its employees a tuition reimbursement program as well as reimbursement for the costs of professional certifications.

Diversity and Inclusion. EOG believes gender, racial, ethnic and cultural diversity, and diversity in background and experience, leads to diversity of thought, which is valued by EOG. As part of its effort to build and maintain a diverse and inclusive workplace, EOG focuses on creating a collaborative culture that fosters inclusion at all levels of the company and reflects the diversity of thought of its employees. EOG also takes steps to raise employee awareness, provide leadership and offer training to help advance diversity and inclusion within EOG. Further, as reflected in its Code of Business Conduct and Ethics for Directors, Officers and Employees, EOG is committed to providing equal opportunity in all aspects of employment and to hiring, evaluating and promoting employees based on skills and performance.

Safety. EOG's safety management programs and processes provide a framework within which management can assess safety performance in a systematic way. EOG's safety performance is also considered in evaluating employee performance and compensation. EOG provides initial, periodic and refresher safety training to employees as well as to contractors and others who may work at or visit EOG's facilities. These training programs address various topics, including operating procedures, safe work practices and emergency and incident response procedures.

Competition

EOG competes with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services, and employees and other personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce, market and transport crude oil, NGLs and natural gas. Certain of EOG's competitors have financial and other resources substantially greater than those EOG possesses and have established strategic long-term positions or strong governmental relationships in countries or areas in which EOG may seek new or expanded entry. As a consequence, EOG may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, EOG's larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil, NGLs and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition from competing energy sources, such as renewable energy sources. See ITEM 1A, Risk Factors.

Regulation

General. New or revised rules, regulations and policies may be issued, and new legislation may be proposed, that could impact the oil and gas exploration and production industry. Such rules, regulations, policies and legislation may affect, among other things, (i) permitting for oil and gas drilling on federal lands, (ii) the leasing of federal lands for oil and gas development, (iii) the regulation of greenhouse gas (GHG) emissions and/or other climate change-related matters associated with oil and gas operations, (iv) the use of hydraulic fracturing on federal lands, (v) the calculation of royalty payments in respect of oil and gas production from federal lands and (vi) U.S. federal income tax laws applicable to oil and gas exploration and production companies. For additional discussion regarding the regulatory-related risks to which EOG's operations, financial condition and results of operations are or may be subject, see the below discussion and ITEM 1A, Risk Factors.

United States Regulation of Crude Oil and Natural Gas Production. Crude oil and natural gas production operations are subject to various types of regulation, including regulation by federal and state agencies.

United States legislation affecting the oil and gas industry is under constant review for amendment or expansion. In addition, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations applicable to the oil and gas industry. Such rules and regulations, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas through restrictions on flaring, require surety bonds for various exploration and production operations and regulate the calculation and disbursement of royalty payments (for federal and state leases), production taxes and ad valorem taxes.

A portion of EOG's oil and gas leases in New Mexico, North Dakota, Utah, Wyoming and the Gulf of Mexico, as well as in other areas, are granted by the federal government and administered by the Bureau of Land Management (BLM) and/or the Bureau of Indian Affairs (BIA) or, in the case of offshore leases (which, for EOG, are de minimis), by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), all federal agencies. Operations conducted by EOG on federal oil and gas leases must comply with numerous additional statutory and regulatory restrictions and, in the case of leases relating to tribal lands, certain tribal environmental and permitting requirements and employment rights regulations. In addition, the U.S. Department of the Interior (via various of its agencies, including the BLM, the BIA and the Office of Natural Resources Revenue) has certain authority over our calculation and payment of royalties, bonuses, fines, penalties, assessments and other revenues related to our federal and tribal oil and gas leases.

BLM, BIA and BOEM leases contain relatively standardized terms requiring compliance with detailed regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act (which are subject to change by the BOEM or BSEE). Under certain circumstances, the BLM, BIA, BOEM or BSEE (as applicable) may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect EOG's interests on federal lands. From time to time, the U.S. Department of the Interior has also considered limiting or pausing new oil and natural gas leases on federal lands or in offshore waters. Any limitation or ban on permitting for oil and gas exploration and production activities on federal lands could have a material and adverse effect on EOG's operations, financial condition and results of operations.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938, as amended (NGA), and the Natural Gas Policy Act of 1978. These statutes are administered by the Federal Energy Regulatory Commission (FERC). Effective January 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, may be subject in the future to greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and NGLs by EOG are made at unregulated market prices.

EOG owns certain gathering and/or processing facilities supporting EOG's operations in the Permian Basin in West Texas and New Mexico, the Fort Worth Basin Barnett Shale in North Texas, the Williston Basin Bakken and Three Forks plays in North Dakota, and the Eagle Ford in South Texas. State regulation of gathering and processing facilities generally includes various safety, environmental and, in some circumstances, nondiscrimination requirements with respect to the provision of gathering and processing services, but does not generally entail rate regulation. EOG's gathering and processing operations could be materially and adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's gathering and processing operations also may be, or become, subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, such legislation might have on its operations and financial condition, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future legislative and regulatory changes.

EOG also owns crude oil rail loading facilities in North Dakota and crude oil truck unloading facilities in certain of its U.S. plays. Regulation of such facilities is conducted at the state and federal levels and generally includes various safety, environmental, permitting and packaging/labeling requirements. Additional regulation pertaining to these matters is considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, any such new regulations might have on its crude-by-rail assets and the transportation of its crude oil production by truck, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future regulatory changes. EOG did not transport any crude oil by rail during 2021.

Proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the state legislatures, the FERC and other federal, state and local regulatory commissions, agencies, councils and courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the oil and gas industry historically has been very heavily regulated; therefore, there is no assurance that the approach currently being followed by such legislative bodies and regulatory commissions, agencies, councils and courts will remain unchanged.

Environmental Regulation Generally - United States. EOG is subject to various federal, state and local laws and regulations covering the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations affect EOG's operations and costs as a result of their effect on crude oil and natural gas exploration, development and production operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements.

In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. EOG also could incur costs related to the clean-up of third-party sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such third-party sites. In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG previously owned or currently owns an interest, but was or is not the operator. Moreover, EOG is subject to the U.S. Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of GHG emissions and, as discussed further below, is also subject to federal, state and local laws and regulations regarding hydraulic fracturing and other aspects of our operations.

Compliance with environmental laws and regulations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, EOG is unable to predict (i) the timing, scope and effect of any currently proposed or future laws or regulations regarding the environment and (ii) the ultimate cost of compliance or the ultimate effect on EOG's operations, financial condition and results of operations relating to such future laws and regulations. The direct and indirect cost of such laws and regulations (in enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Climate Change - United States. Local, state, federal and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. The U.S. Congress has, from time to time, proposed legislation for imposing restrictions or requiring fees or carbon taxes for GHG emissions. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, the U.S. EPA has adopted regulations for certain large sources regulating GHG emissions as pollutants under the federal Clean Air Act. Further, the U.S. EPA, in May 2016, issued regulations that require operators to reduce methane emissions and emissions of volatile organic compounds (VOC) from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector.

At the international level, the U.S., in December 2015, participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. The Paris Agreement went into effect on November 4, 2016 and which the United States formally rejoined in February 2021. The United States has established economy-wide targets of (i) reducing its net GHG emissions by 50-52 percent below 2005 levels by 2030 and (ii) achieving net zero GHG emissions economy-wide by no later than 2050. In addition, many state and local officials have stated their intent to intensify efforts to uphold the commitments set forth in the international accord. Further, in November 2021, the U.S. Department of the Interior released its "Report on the Federal Oil and Gas Leasing Program," which recommended increasing royalties associated with oil and gas resources extracted from federal lands and offshore waters to account for corresponding climate costs.

EOG believes that its strategy to reduce GHG emissions throughout its operations is both in the best interest of the environment and a prudent business practice. EOG has developed a system that is utilized in calculating GHG emissions from its operating facilities. This emissions management system calculates emissions based on recognized regulatory methodologies, where applicable, and on commonly accepted engineering practices. EOG reports GHG emissions for facilities covered under the U.S. EPA's Mandatory Reporting of Greenhouse Gases Rule published in 2009, as amended.

EOG is unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations, treaties or policies regarding climate change and GHG emissions (including any laws and regulations that may be enacted in the U.S.), but the direct and indirect costs of such investigations, laws, regulations, treaties or policies (if enacted, issued or applied) could materially and adversely affect EOG's operations, financial condition and results of operations. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emissions controls on our facilities, acquire allowances or credits to cover our GHG emissions, pay taxes or fees related to our GHG emissions, or administer and manage a GHG emissions program. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to GHG emissions, or restrictions on their use, could also adversely affect market demand for, and in turn the prices we receive for our production of, crude oil, NGLs and natural gas. Further, the increasing attention to global climate change risks has created the potential for a greater likelihood of governmental investigations and private and public litigation, which could increase our costs or otherwise adversely affect our business. See ITEM 1A, Risk Factors, for additional discussion regarding climate change-related developments..

Regulation of Hydraulic Fracturing and Other Operations - United States. Substantially all of the onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. Hydraulic fracturing technology, which has been used by the oil and gas industry for more than 60 years and is constantly being enhanced, enables EOG to produce crude oil and natural gas that otherwise would not be recovered. Specifically, hydraulic fracturing is a process in which pressurized fluid is pumped into underground formations to create tiny fractures or spaces that allow crude oil and natural gas to flow from the reservoir into the well so that it can be brought to the surface. Hydraulic fracturing generally takes place thousands of feet underground, a considerable distance below any drinking water aquifers, and there are impermeable layers of rock between the area fractured and the water aquifers. The makeup of the fluid used in the hydraulic fracturing process typically includes water and sand, and less than 1% of highly diluted chemical additives; lists of the chemical additives used in fracturing fluids are available to the public via internet websites and in other publications sponsored by industry trade associations and through state agencies in those states that require the reporting of the components of fracturing fluids. While the majority of the sand remains underground to hold open the fractures, a significant amount of the water and chemical additives flow back and are then either reused or safely disposed of at sites that are approved and permitted by the appropriate regulatory authorities. EOG periodically conducts regulatory assessments of these disposal facilities to monitor compliance with applicable regulations.

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. In April 2012, however, the U.S. EPA issued regulations specifically applicable to the oil and gas industry that require operators to significantly reduce VOC emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The U.S. EPA has also issued regulations that establish standards for VOC emissions from several types of equipment, including storage tanks, compressors, dehydrators, and valves and sweetening units at gas processing plants. In addition, in May 2016, the U.S. EPA issued regulations that require operators to reduce methane and VOC emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. From time to time, there have been various other proposals to regulate hydraulic fracturing at the federal level.

In addition to the above-described federal regulations, some state and local governments have imposed, or have considered imposing, various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; disclosure of the chemical additives used in hydraulic fracturing operations; restrictions on the type of chemical additives that may be used in hydraulic fracturing operations; and restrictions on drilling or injection activities on certain lands lying within wilderness wetlands, ecologically or seismically sensitive areas, and other protected areas. Such federal, state and local permitting and disclosure requirements, operating restrictions, conditions or prohibition could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

Compliance with laws and regulations relating to hydraulic fracturing and other aspects of our operations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, EOG is unable to predict (i) the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing in the United States or other aspects of our operations and (ii) the ultimate cost of compliance or the ultimate effect on EOG's operations, financial condition and results of operations relating to such future laws and regulations. The direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Other International Regulation. EOG's exploration and production operations outside the United States are subject to various types of regulations, including environmental regulations, imposed by the respective governments of the countries in which EOG's operations are conducted, and may affect EOG's operations and costs of compliance within those countries. EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations. EOG will continue to review the risks to its business and operations outside the United States associated with all environmental matters, including climate change and hydraulic fracturing regulation. In addition, EOG will continue to monitor and assess any new policies, legislation, regulations and treaties in the areas outside the United States where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Other Matters

Energy Prices. EOG is a crude oil and natural gas producer and is impacted by changes in the prices for crude oil and condensate, NGLs and natural gas. During the last three years, average United States commodity prices have fluctuated, at times rather dramatically. Average crude oil and condensate prices received by EOG for production in the United States increased 77% in 2021, decreased 33% in 2020 and decreased 11% in 2019, each as compared to the immediately preceding year. Average NGL prices received by EOG for production in the United States increased 156% in 2021, decreased 16% in 2020 and decreased 40% in 2019, each as compared to the immediately preceding year. Fluctuations in average natural gas prices received by EOG for production in the United States resulted in a 203% increase in 2021, a 27% decrease in 2020, and a 23% decrease in 2019, each as compared to the immediately preceding year.

Due to the many uncertainties associated with the world political and economic environment (for example, the actions of other crude oil exporting nations, including the Organization of Petroleum Exporting Countries, and the duration and impact of the ongoing COVID-19 pandemic), the global supply of, and demand for, crude oil, NGLs and natural gas and the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors, EOG is unable to predict what changes may occur in the prices of crude oil and condensate, NGLs and natural gas in the future. For additional discussion regarding changes in crude oil and condensate, NGLs and natural gas prices, the potential impacts on EOG and the risks that such changes may present to EOG, see ITEM 1A, Risk Factors.

Including the impact of EOG's crude oil and NGL derivative contracts (exclusive of basis swaps) and based on EOG's tax position, EOG's price sensitivity in 2022 for each \$1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately \$107 million for net income and \$138 million for pretax cash flows from operating activities. Including the impact of EOG's natural gas derivative contracts and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2022 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each \$0.10 per Mcf increase or decrease in wellhead natural gas price is approximately \$15 million for net income and \$19 million for pretax cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts through February 18, 2022, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions. For a summary of EOG's financial commodity derivative contracts for the year ended December 31, 2021, see Note 12 to Consolidated Financial Statements.

Risk Management. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in prices of crude oil, NGLs and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. See Note 12 to Consolidated Financial Statements. For a summary of EOG's financial commodity derivative contracts through February 18, 2022, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions.

All of EOG's crude oil, NGL and natural gas activities are subject to the risks normally incident to the exploration for, and development, production and transportation of, crude oil, NGL and natural gas, including rig and well explosions, cratering, fires, loss of well control and leaks and spills, each of which could result in damage to life, property and/or the environment. EOG's operations are also subject to certain perils, including hurricanes, flooding and other adverse weather events. Moreover, EOG's activities are subject to governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events could reduce EOG's revenues and increase costs to EOG to the extent not covered by insurance.

Insurance is maintained by EOG against some, but not all, of these risks in accordance with what EOG believes are customary industry practices and in amounts and at costs that EOG believes to be prudent and commercially practicable. Specifically, EOG maintains commercial general liability and excess liability coverage provided by third-party insurers for bodily injury or death claims resulting from an incident involving EOG's operations (subject to policy terms and conditions). Moreover, for any incident involving EOG's operations which results in negative environmental effects, EOG maintains operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that EOG may incur from such an incident, including obligations, expenses or claims in respect of seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the event of a well control incident resulting in negative environmental effects, such operators extra expense coverage would be EOG's primary coverage, with the commercial general liability and excess liability coverage referenced above also providing certain coverage to EOG. All of EOG's drilling activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. The indemnification and other risk allocation provisions included in such contracts are negotiated on a contract-by-contract basis and are each based on the particular circumstances of the services being provided and the anticipated operations.

In addition to the above-described risks, EOG's operations outside the United States are subject to certain risks, including the risk of increases in taxes and governmental royalties, changes in laws and policies governing the operations of foreign-based companies, expropriation of assets, unilateral or forced renegotiation, modification or nullification of existing contracts with governmental entities, currency restrictions and exchange rate fluctuations. Please refer to ITEM 1A, Risk Factors, for further discussion of the risks to which EOG is subject with respect to its operations outside the United States.

Information About Our Executive Officers

The current executive officers of EOG and their names and ages (as of February 24, 2022) are as follows:

<u>Name</u>	<u>Age</u>	<u>Position</u>
Ezra Y. Yacob	45	Chief Executive Officer
Lloyd W. Helms, Jr.	64	President and Chief Operating Officer
Kenneth W. Boedeker	59	Executive Vice President, Exploration and Production
Jeffrey R. Leitzell	42	Executive Vice President, Exploration and Production
Timothy K. Driggers	60	Executive Vice President and Chief Financial Officer
Michael P. Donaldson	59	Executive Vice President, General Counsel and Corporate Secretary

Ezra Y. Yacob was elected Chief Executive Officer and appointed as a Director effective October 2021. Prior to that, he served as President from January 2021 through September 2021; Executive Vice President, Exploration and Production from December 2017 to January 2021; and Vice President and General Manager of EOG's Midland, Texas office from May 2014 to December 2017. He also previously served as Manager, Division Exploration in EOG's Fort Worth, Texas, and Midland, Texas, offices from March 2012 to May 2014 as well as in various geoscience and leadership positions. Mr. Yacob joined EOG in August 2005.

Lloyd W. Helms, Jr. was elected President and Chief Operating Officer effective October 2021. Mr. Helms has served as Chief Operating Officer since December 2017. Prior to that, he served as Executive Vice President, Exploration and Production from August 2013 to December 2017. He was elected Vice President, Engineering and Acquisitions in September 2006, Vice President and General Manager of EOG's Calgary, Alberta, Canada office in March 2008, and served as Executive Vice President, Operations from February 2012 to August 2013. Mr. Helms joined a predecessor of EOG in February 1981.

Kenneth W. Boedeker was elected Executive Vice President, Exploration and Production in December 2018. He served as Vice President and General Manager of EOG's Denver, Colorado, office from October 2016 to December 2018, and as Vice President, Engineering and Acquisitions from July 2015 to October 2016. Prior to that, Mr. Boedeker held technical and managerial positions of increasing responsibility across multiple offices and functional areas within EOG. Mr. Boedeker joined EOG in July 1994.

Jeffrey R. Leitzell was elected Executive Vice President, Exploration and Production in May 2021. Mr. Leitzell previously served as Vice President and General Manager of EOG's Midland, Texas office from December 2017 to May 2021 and as Operations Manager in Midland from August 2015 to December 2017. Prior to that, Mr. Leitzell held various engineering roles of increasing responsibility in multiple offices and functional areas within EOG. Mr. Leitzell joined EOG in October 2008.

Timothy K. Driggers was elected Executive Vice President and Chief Financial Officer in April 2016. Previously, Mr. Driggers served as Vice President and Chief Financial Officer from July 2007 to April 2016. He was elected Vice President and Controller of EOG in October 1999, was subsequently named Vice President, Accounting and Land Administration in October 2000 and Vice President and Chief Accounting Officer in August 2003. Mr. Driggers is EOG's principal financial officer. Mr. Driggers joined a predecessor of EOG in August 1995.

Michael P. Donaldson was elected Executive Vice President, General Counsel and Corporate Secretary in April 2016. Previously, Mr. Donaldson served as Vice President, General Counsel and Corporate Secretary from May 2012 to April 2016. He was elected Corporate Secretary in May 2008, and was appointed Deputy General Counsel and Corporate Secretary in July 2010. Mr. Donaldson joined EOG in September 2007.

ITEM 1A. Risk Factors

Our business and operations are subject to many risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition, results of operations or cash flows could be materially and adversely affected and the trading price of our common stock could decline. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes. Unless the context requires otherwise, "we," "us," "our" and "EOG" refer to EOG Resources, Inc. and its subsidiaries.

Risks Related to our Financial Condition, Results of Operations and Cash Flows

Crude oil, NGLs and natural gas prices are volatile, and a substantial and extended decline in commodity prices can have a material and adverse effect on us.

Prices for crude oil and natural gas (including prices for natural gas liquids (NGLs) and condensate) fluctuate widely. Among the interrelated factors that can or could cause these price fluctuations are:

- domestic and worldwide supplies of, and consumer and industrial/commercial demand for, crude oil, NGLs and natural gas;
- domestic and international drilling activity;
- the actions of other crude oil producing and exporting nations, including the Organization of Petroleum Exporting Countries;
- worldwide economic conditions, geopolitical factors and political conditions, including, but not limited to, the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions;
- the duration and economic and financial impact of epidemics, pandemics or other public health issues, such as the ongoing COVID-19 pandemic;
- the availability, proximity and capacity of appropriate transportation, gathering, processing, compression, storage, refining and export facilities;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the effect of worldwide energy conservation measures, alternative fuel requirements and climate change-related policies, initiatives and developments;
- technological advances and consumer and industrial/commercial behavior, preferences and attitudes, in each case affecting energy generation, transmission, storage and consumption;
- the nature and extent of governmental regulation, including environmental and other climate change-related regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of crude oil, NGLs, and natural gas and related commodities;
- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others; and
- natural disasters, weather conditions and changes in weather patterns.

The above-described factors and the volatility of commodity prices make it difficult to predict crude oil, NGLs and natural gas prices in 2022 and thereafter. As a result, there can be no assurance that the prices for crude oil, NGLs and/or natural gas will sustain, or increase from, their current levels, nor can there be any assurance that the prices for crude oil, NGLs and/or natural gas will not decline.

Our cash flows, financial condition and results of operations depend to a great extent on prevailing commodity prices. Accordingly, substantial and extended declines in commodity prices can materially and adversely affect the amount of cash flows we have available for our capital expenditures and operating expenses; the terms on which we can access the credit and capital markets; our results of operations; and our financial condition, including (but not limited to) our ability to pay dividends on our common stock. As a result, the trading price of our common stock may be materially and adversely affected.

Lower commodity prices can also reduce the amount of crude oil, NGLs and natural gas that we can produce economically. Substantial and extended declines in the prices of these commodities can render uneconomic a portion of our exploration, development and exploitation projects, resulting in our having to make downward adjustments to our estimated proved reserves and also possibly shut in or plug and abandon certain wells. In addition, significant prolonged decreases in commodity prices may cause the expected future cash flows from our properties to fall below their respective net book values, which would require us to write down the value of our properties. Such reserve write-downs and asset impairments can materially and adversely affect our results of operations and financial position and, in turn, the trading price of our common stock.

Developments related to climate change may have a material and adverse effect on us.

Governmental and regulatory bodies, investors, consumers, industry and other stakeholders have been increasingly focused on climate change matters in recent years. This focus, together with changes in consumer and industrial/commercial behavior, preferences and attitudes with respect to the generation and consumption of energy, the use of crude oil, NGLs and natural gas and the use of products manufactured with, or powered by, crude oil, NGLs and natural gas, may result in (i) the enactment of climate change-related regulations, policies and initiatives (at the government, corporate and/or investor community levels), including alternative energy requirements and energy conservation measures, (ii) technological advances with respect to the generation, transmission, storage and consumption of energy (e.g., wind, solar and hydrogen power, smart grid technology and battery technology) and (iii) increased availability of, and increased consumer and industrial/commercial demand for, non-hydrocarbon energy sources (e.g., alternative energy sources) and products manufactured with, or powered by, non-hydrocarbon sources (e.g., electric vehicles and renewable residential and commercial power supplies). These developments may adversely affect the demand for products manufactured with, or powered by, crude oil, NGLs and natural gas and the demand for, and in turn the prices of, the crude oil, NGLs and natural gas that we sell. See the risk factor above for a discussion of the impact of commodity prices (including fluctuations in commodity prices) on our financial condition, cash flows and results of operations.

In addition to potentially adversely affecting the demand for, and prices of, the crude oil, NGLs and natural gas that we sell, such developments may also adversely impact, among other things, the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to explore for, produce, transport and process crude oil, NGLs and natural gas and successfully carry out our business strategy. For further discussion of the potential impact of such risks on our financial condition and results of operations, see the discussion in the section below entitled "Risks Related to our Operations."

Further, climate change-related developments may result in negative perceptions of the oil and gas industry and, in turn, reputational risks associated with the exploration for, and production of, hydrocarbons. Such negative perceptions and reputational risks may adversely affect our ability to successfully carry out our business strategy, for example, by adversely affecting the availability and cost to us of capital. For further discussion of the potential impact of such risks on our financial condition, cash flows and results of operations, see the discussion below in this section and in the section below entitled "Risks Related to Regulatory and Legal Matters."

In addition, the enactment of climate change-related regulations, policies and initiatives (at the government, corporate and/or investor community levels) may also result in increases in our compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation). For further discussion regarding the risks to us of climate change-related regulations, policies and initiatives, see the discussion below in the section entitled "Risks Related to Regulatory and Legal Matters."

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms, if at all.

We make, and expect to continue to make, substantial capital expenditures for the acquisition, exploration, development and production of crude oil, NGLs and natural gas reserves. We intend to finance our capital expenditures primarily through our cash flows from operations, cash on hand and sales of non-core assets and, to a lesser extent and if and as necessary, commercial paper borrowings, bank borrowings, borrowings under our revolving credit facility and public and private equity and debt offerings.

Lower crude oil, NGLs and natural gas prices, however, reduce our cash flows and could also delay or impair our ability to consummate certain planned non-core asset sales and divestitures. Further, if the condition of the credit and capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable, if at all. In addition, weakness and/or volatility in domestic and global financial markets or economic conditions or a depressed commodity price environment may increase the interest rates that lenders and commercial paper investors require us to pay or adversely affect our ability to finance our capital expenditures through equity or debt offerings or other borrowings.

Similarly, a reduction in our cash flows (for example, as a result of lower crude oil, natural gas and/or NGLs prices or unanticipated well shut-ins) and the corresponding adverse effect on our financial condition and results of operations may also increase the interest rates that lenders and commercial paper investors require us to pay. A substantial increase in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations.

Further, our ability to obtain financings, our borrowing costs and the terms of any financings are, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. The interrelated factors that may impact our credit ratings include our debt levels; planned capital expenditures and sales of assets; near-term and long-term production growth opportunities; liquidity; asset quality; cost structure; product mix; and commodity pricing levels (including, but not limited to, the estimates and assumptions of credit rating agencies with respect to future commodity prices). We cannot provide any assurance that our current credit ratings will remain in effect for any given period of time or that our credit ratings will be raised in the future, nor can we provide any assurance that any of our credit ratings will not be lowered.

In addition, companies in the oil and gas sector may be exposed to increasing reputational risks and, in turn, certain financial risks. Specifically, certain financial institutions (including certain investment advisors and sovereign wealth, pension and endowment funds), in response to concerns related to climate change and the requests and other influence of environmental groups and similar stakeholders, have elected to shift some or all of their investments away from oil and gas-related sectors, and additional financial institutions and other investors may elect to do likewise in the future. As a result, fewer financial institutions and other investors may be willing to invest in, and provide capital to, companies in the oil and gas sector. A material reduction in capital available to the oil and gas sector could make it more difficult (e.g., due to a lack of investor interest in our equity or debt securities) and/or more costly (e.g., due to higher interest rates on our debt securities or other borrowings) to secure funding for our operations, which, in turn, could adversely affect our ability to successfully carry out our business strategy and have a material and adverse effect on our business, financial condition and operations.

Reserve estimates depend on many interpretations and assumptions. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities of our reserves to be materially misstated.

Estimating quantities of crude oil, NGLs and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Also, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, continual reassessment of the viability of production under varying economic conditions and improvements and other changes in geological, geophysical and engineering evaluation methods.

To prepare estimates of our economically recoverable crude oil, NGLs and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, gathering, processing, compression, storage and transportation costs, severance, ad valorem and other applicable taxes, capital expenditures and workover and remedial costs. Many of these factors are or may be beyond our control. Our actual reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance, including any significant downward revisions to our existing reserve estimates, could materially and adversely affect our business, financial condition and results of operations and, in turn, the trading price of our common stock. For related discussion, see ITEM 2, Properties - Oil and Gas Exploration and Production - Properties and Reserves and Supplemental Information to Consolidated Financial Statements.

If we fail to acquire or find sufficient additional reserves over time, our reserves and production will decline from their current levels.

The rate of production from crude oil and natural gas properties generally declines as reserves are produced. Except to the extent that we conduct successful exploration, exploitation and development activities resulting in additional reserves, acquire additional properties containing reserves or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our reserves will decline as they are produced. Maintaining our production of crude oil and natural gas at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves, which may be adversely impacted by bans or restrictions on drilling. To the extent we are unsuccessful in acquiring or finding additional reserves, our future cash flows and results of operations and, in turn, the trading price of our common stock could be materially and adversely affected.

Our ability to declare and pay dividends is subject to certain considerations.

Dividends are authorized and determined by our Board of Directors (Board) in its sole discretion and depend upon a number of factors, including:

- cash available for dividends;
- our results of operations and anticipated future results of operations;
- our financial condition, especially in relation to the anticipated future capital expenditures required to conduct our operations;
- our operating expenses;
- the levels of dividends paid by comparable companies; and
- other factors our Board deems relevant.

We expect to continue to pay dividends to our stockholders; however, our Board may reduce our dividend or cease declaring dividends at any time, including if it determines that our current or forecasted future cash flows provided by our operating activities (after deducting our capital expenditures and other commitments) are not sufficient to pay our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all. Any downward revision in the amount of dividends we pay to stockholders could have an adverse effect on the trading price of our common stock.

Our hedging activities may prevent us from fully benefiting from increases in crude oil, NGLs and natural gas prices and may expose us to other risks, including counterparty risk.

We use derivative instruments (primarily financial basis swap, price swap, option, swaption and collar contracts) to hedge the impact of fluctuations in crude oil, NGLs and natural gas prices on our results of operations and cash flows. To the extent that we engage in hedging activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of increases in crude oil, NGLs and natural gas prices above the prices established by our hedging contracts. A portion of our forecasted production for 2022 is subject to fluctuating market prices. If we are ultimately unable to hedge additional production volumes for 2022 and beyond, we may be materially and adversely impacted by any declines in commodity prices, which may result in lower net cash provided by operating activities. In addition, our hedging activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

The inability of our customers and other contractual counterparties to satisfy their obligations to us may have a material and adverse effect on us.

We have various customers for the crude oil, natural gas and related commodities that we produce as well as various other contractual counterparties, including several financial institutions and affiliates of financial institutions. Domestic and global economic conditions, including the financial condition of financial institutions generally, may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes.

Moreover, our customers and other contractual counterparties may be unable to satisfy their contractual obligations to us for reasons unrelated to these conditions and factors, such as (i) the unavailability of required facilities or equipment due to mechanical failure or market conditions or (ii) financial, operational or strategic actions taken by the customer or counterparty that adversely impact its financial condition, results of operations and cash flows and, in turn, its ability to satisfy its contractual obligations to us. Furthermore, if a customer is unable to satisfy its contractual obligation to purchase crude oil, natural gas or related commodities from us, we may be unable to sell such production to another customer on terms we consider acceptable, if at all, due to the geographic location of such production; the availability, proximity and capacity of appropriate gathering, processing, compression, storage, transportation, export and refining facilities; or market or other factors and conditions.

The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us may materially and adversely affect our business, financial condition, results of operations and cash flows.

Risks Related to our Operations

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil, NGLs and/or natural gas reserves. As a result, we may not recover all or any portion of our investment in new wells.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- leasehold title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding, tropical storms and hurricanes, and changes in weather patterns;
- compliance with, or changes in (including the adoption of new), environmental, health and safety laws and regulations relating to air emissions, hydraulic fracturing, access to and use of water, disposal or other discharge (e.g., into injection wells) of produced water, drilling fluids and other wastes, laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil, NGLs and natural gas, and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required federal, state, tribal and other permits and licenses, which may be adversely affected by (among other things) bans or restrictions on drilling, government shutdowns or other suspensions of, or delays in, government services;
- the availability of, costs associated with and terms of contractual arrangements for properties, including mineral licenses and leases, pipelines, crude oil hauling trucks and qualified drivers and facilities and equipment to gather, process, compress, store, transport, market and export crude oil, NGLs and natural gas and related commodities; and
- the costs of, or shortages or delays in the availability of, drilling rigs, hydraulic fracturing services, pressure pumping equipment and supplies, tubular materials, water, sand, disposal facilities, qualified personnel and other necessary facilities, equipment, materials, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators, in each case, due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

Our crude oil, NGLs and natural gas operations and supporting activities and operations involve many risks and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our crude oil, NGLs and natural gas operations and supporting activities and operations are subject to all of the risks associated with exploring and drilling for, and producing, gathering, processing, compressing, storing, transporting and exporting crude oil, NGLs and natural gas, including the risks of:

- well blowouts and cratering;
- loss of well control;
- crude oil spills, natural gas leaks, formation water (i.e., produced water) spills and pipeline ruptures;
- pipe failures and casing collapses;
- uncontrollable flows of crude oil, natural gas, formation water or drilling fluids;
- releases of chemicals, wastes or pollutants;
- adverse weather events, such as winter storms, flooding, tropical storms and hurricanes, and other natural disasters;
- fires and explosions;
- terrorism, vandalism and physical, electronic and cybersecurity breaches;
- formations with abnormal or unexpected pressures;
- leaks or spills in connection with, or associated with, the gathering, processing, compression, storage, transportation and export of crude oil, NGLs and natural gas; and
- malfunctions of, or damage to, gathering, processing, compression and transportation facilities and equipment and other facilities and equipment utilized in support of our crude oil and natural gas operations.

If any of these events occur, we could incur losses, liabilities and other additional costs as a result of:

- injury or loss of life;
- damage to, or destruction of, property, facilities, equipment and crude oil and natural gas reservoirs;
- pollution or other environmental damage;
- regulatory investigations and penalties as well as cleanup and remediation responsibilities and costs;
- suspension or interruption of our operations, including due to injunction;
- repairs necessary to resume operations; and
- compliance with laws and regulations enacted as a result of such events.

We maintain insurance against many, but not all, such losses and liabilities in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. However, the occurrence of any of these events and any losses or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage, would reduce the funds available to us for our operations and could, in turn, have a material and adverse effect on our business, financial condition and results of operations. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums, retentions and deductibles for our insurance policies will change over time and could escalate. In addition, some forms of insurance may become unavailable or unavailable on economically acceptable terms.

Our ability to sell and deliver our crude oil, NGLs and natural gas production could be materially and adversely affected if adequate gathering, processing, compression, storage, transportation and export facilities and equipment are unavailable.

The sale of our crude oil, NGLs and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of, and costs associated with, gathering, processing, compression, storage, transportation and export facilities and equipment owned by third parties. These facilities and equipment may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. In particular, in certain newer plays, the capacity of gathering, processing, compression, storage, transportation and export facilities and equipment may not be sufficient to accommodate potential production from existing and new wells. In addition, lack of financing, construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new gathering, processing, compression, storage, transportation and export facilities and equipment by third parties or us, and we may experience delays or increased costs in accessing the pipelines, gathering systems or rail systems necessary to transport our production to points of sale or delivery.

Any significant change in market or other conditions affecting gathering, processing, compression, storage, transportation and export facilities and equipment or the availability of these facilities and equipment, including due to our failure or inability to obtain access to these facilities and equipment on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

A portion of our crude oil, NGLs and natural gas production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our crude oil, NGLs and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, the unavailability of gathering, processing, compression, storage, transportation, refining or export facilities or equipment or field labor issues, or intentionally as a result of market conditions such as crude oil, NGLs or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted or shut in, our cash flows and, in turn, our financial condition and results of operations could be materially and adversely affected.

Our operations are substantially dependent upon the availability of water. Restrictions on our ability to obtain water may have a material and adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of our operations, both during the drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought) could materially and adversely impact our operations. Further, severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

We have limited control over the activities on properties that we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil, NGLs or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

If we acquire crude oil, NGLs and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems (such as title or environmental issues), nor may they permit us to become sufficiently familiar with the properties in order to fully assess their deficiencies and potential. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements.

In addition, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further above), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

Competition in the oil and gas exploration and production industry is intense, and some of our competitors have greater resources than we have.

We compete with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services and employees and other personnel (including geologists, geophysicists, engineers and other specialists) necessary to explore for, develop, produce, market and transport crude oil, NGLs and natural gas. Certain of our competitors have financial and other resources substantially greater than those we possess and have established strategic long-term positions or strong governmental relationships in countries or areas in which we may seek new or expanded entry. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil, NGLs and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition from competing energy sources, such as renewable energy sources.

Risks Related to Our International Operations

We operate in other countries and, as a result, are subject to certain political, economic and other risks.

Our operations in jurisdictions outside the U.S. are subject to various risks inherent in foreign operations. These risks include, among other risks:

- increases in taxes and governmental royalties;
- changes in laws and policies governing operations of foreign-based companies;
- loss of revenue, loss of or damage to equipment, property and other assets and interruption of operations as a result of expropriation, nationalization, acts of terrorism, war, civil unrest and other political risks;
- unilateral or forced renegotiation, modification or nullification of existing contracts with governmental entities;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- currency restrictions or exchange rate fluctuations.

Our international operations may also be adversely affected by U.S. laws and policies affecting foreign trade and taxation, including tariffs or trade or other economic sanctions; modifications to, or withdrawal from, international trade treaties; and U.S. laws with respect to participation in boycotts that are not supported by the U.S. government. The realization of any of these factors could materially and adversely affect our business, financial condition and results of operations.

Unfavorable currency exchange rate fluctuations could materially and adversely affect our results of operations.

The reporting currency for our financial statements is the U.S. dollar. However, certain of our subsidiaries are located in countries other than the U.S. and have functional currencies other than the U.S. dollar. The assets, liabilities, revenues and expenses of certain of these foreign subsidiaries are denominated in currencies other than the U.S. dollar. To prepare our consolidated financial statements, we must translate those assets, liabilities, revenues and expenses into U.S. dollars at then-applicable exchange rates. Consequently, increases and decreases in the value of the U.S. dollar versus other currencies will affect the amount of these items in our consolidated financial statements, even if the amount has not changed in the original currency. These translations could result in changes to our results of operations from period to period. For the fiscal year ended December 31, 2021, EOG had no net operating revenues related to operations of our foreign subsidiaries whose functional currency was not the U.S. dollar.

Risks Related to Regulatory and Legal Matters

Regulatory, legislative and policy changes may materially and adversely affect the oil and gas exploration and production industry.

New or revised rules, regulations and policies may be issued, and new legislation may be proposed, that could impact the oil and gas exploration and production industry. Such rules, regulations, policies and legislation may affect, among other things, (i) permitting for oil and gas drilling on federal lands, (ii) the leasing of federal lands for oil and gas development, (iii) the regulation of greenhouse gas (GHG) emissions and/or other climate change-related matters associated with oil and gas operations, (iv) the use of hydraulic fracturing on federal lands, (v) the calculation of royalty payments in respect of oil and gas production from federal lands (including, but not limited to, an increase in applicable royalty percentages) and (vi) U.S. federal income tax laws applicable to oil and gas exploration and production companies.

Further, such regulatory, legislative and policy changes may, among other things, result in additional permitting and disclosure requirements, additional operating restrictions and/or the imposition of various conditions and restrictions on drilling and completion operations or other aspects of our business, any of which could lead to operational delays, increased operating and compliance costs and/or other impacts on our business and operations and could materially and adversely affect our business, results of operations and financial condition.

For related discussion, see the below risk factors regarding legislative and regulatory matters impacting the oil and gas exploration and production industry and the discussion in ITEM 1, Business - Regulation.

We incur certain costs to comply with government regulations, particularly regulations relating to environmental protection and safety, and could incur even greater costs in the future.

Our crude oil, NGLs and natural gas operations and supporting activities are regulated extensively by federal, state, tribal and local governments and regulatory agencies, both domestically and in the foreign countries in which we do business, and are subject to interruption or termination by governmental and regulatory authorities based on environmental, health, safety or other considerations. Moreover, we have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, health, safety and other regulations. Further, the regulatory environment could change in ways that we cannot predict and that might substantially increase our costs of compliance and/or adversely affect our business and operations and, in turn, materially and adversely affect our results of operations and financial condition.

Specifically, as a current or past owner or lessee and operator of crude oil and natural gas properties, we are subject to various federal, state, tribal, local and foreign regulations relating to the discharge of materials into, and the protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution cleanup resulting from current or past operations, subject us to liability for pollution damages and require suspension or cessation of operations in affected areas. Changes in, or additions to, these regulations, could lead to increased operating and compliance costs and, in turn, materially and adversely affect our business, results of operations and financial condition.

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements and, further, some state and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations. The U.S. Environmental Protection Agency (U.S. EPA) has issued regulations relating to hydraulic fracturing and there have been various other proposals to regulate hydraulic fracturing at the federal level.

Any new requirements, restrictions, conditions or prohibition could lead to operational delays and increased operating and compliance costs and, further, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. Accordingly, our production of crude oil and natural gas could be materially and adversely affected. For additional discussion regarding hydraulic fracturing regulation, see Regulation of Hydraulic Fracturing and Other Operations - United States under ITEM 1, Business - Regulation.

We will continue to monitor and assess any proposed or new policies, legislation, regulations and treaties in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary. We are unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations and financial condition. See also the risk factor below regarding the provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act with respect to regulation of derivatives transactions and entities (such as EOG) that participate in such transactions.

Regulations, government policies and government and corporate initiatives relating to greenhouse gas emissions and climate change could have a significant impact on our operations and we could incur significant cost in the future to comply.

Local, state, federal and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. For example, we are subject to the U.S. EPA's rule requiring annual reporting of GHG emissions. In addition, our oil and gas production and processing operations are subject to the U.S. EPA's new source performance standards applicable to emissions of volatile organic compounds from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations and gas processing plants.

At the international level, in December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. The Paris Agreement went into effect on November 4, 2016 and to which the United States formally rejoined in February 2021. The United States has established an economy-wide target of reducing its net GHG emissions by 50-52 percent below 2005 levels by 2030 and achieving net zero GHG emissions economy-wide by no later than 2050. In addition, many state and local officials have stated their intent to intensify efforts to uphold the commitments set forth in the international accord. Further, in November 2021, the U.S. Department of the Interior released its "Report on the Federal Oil and Gas Leasing Program", which recommended increasing royalties associated with oil and gas resources extracted from federal lands and offshore waters to account for corresponding climate costs.

It is possible that the Paris Agreement and subsequent domestic and international regulations and government policies related to climate change and GHG emissions will have adverse effects on the market for crude oil, NGLs and natural gas as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, crude oil, NGLs and natural gas. We are unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations, treaties or policies regarding climate change and GHG emissions (including any laws and regulations that may be enacted in the U.S.), but the direct and indirect costs of such developments (if enacted, issued or applied) could materially and adversely affect our operations, financial condition and results of operations. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay taxes or fees related to our GHG emissions, or administer and manage a greenhouse gas emissions program. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to GHG emissions, or restrictions on their use, could also adversely affect market demand for, and in turn the prices we receive for our production of, crude oil, NGLs and natural gas. Further, the increasing attention to global climate change risks has created the potential for a greater likelihood of governmental investigations and private and public litigation, which could increase our costs or otherwise adversely affect our business. For additional discussion regarding climate change regulation, see (i) Climate Change - United States under ITEM 1, Business – Regulation and (ii) the risk factor above with respect to the new U.S. administration.

In addition, the achievement of our current or future internal initiatives relating to the reduction of GHG emissions may increase our costs, including requiring us to purchase emissions credits or offsets, the availability and price of which are outside of our control, or may impact or otherwise limit our ability to execute on our business plans. Further, such initiatives relating to the reduction of GHG emissions could be subject to business, regulatory, economic and competitive uncertainties and contingencies, and required advancements in technology.

Tax laws and regulations applicable to crude oil and natural gas exploration and production companies may change over time, and such changes could materially and adversely affect our cash flows, results of operations and financial condition.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal income tax laws applicable to crude oil and natural gas exploration and production companies, such as with respect to the intangible drilling and development costs deduction and bonus tax depreciation. While these specific changes were not included in the Tax Cuts and Jobs Act signed into law in December 2017, no accurate prediction can be made as to whether any such legislative changes or similar or other tax law changes will be proposed in the future (for example, by the new U.S. administration) and, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of certain U.S. federal income tax deductions, as well as any other changes to, or the imposition of new, federal, state, local or non-U.S. taxes (including the imposition of, or increases in, production, severance or similar taxes), could materially and adversely affect our cash flows, results of operations and financial condition.

In addition, legislation may be proposed with respect to the enactment of a tax levied on the carbon content of fuels based on the GHG emissions associated with such fuels. A carbon tax would generally increase the prices for crude oil, NGLs and natural gas. Such price increases may, in turn, reduce demand for crude oil, NGLs and natural gas and materially and adversely affect our cash flows, results of operations and financial condition.

We are unable to predict the timing, scope and effect of any proposed or enacted tax law changes, but any such changes (if enacted) could materially and adversely affect our business, results of operations and financial condition. We will continue to monitor and assess any proposed or enacted tax law changes to determine the impact on our business, results of operations and financial condition and take appropriate actions, where necessary.

Federal legislation and related regulations regarding derivatives transactions could have a material and adverse impact on our hedging activities.

As discussed in the risk factor above regarding our hedging activities, we use derivative instruments to hedge the impact of fluctuations in crude oil, NGLs and natural gas prices on our results of operations and cash flows. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which, among other matters, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (CFTC), the U.S. Securities and Exchange Commission (SEC) and certain federal agencies that regulate the banking and insurance sectors (the Prudential Regulators) adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act are yet to be adopted, the CFTC, the SEC and the Prudential Regulators have issued numerous rules, including a rule establishing an “end-user” exception to mandatory clearing (End-User Exception), a rule regarding margin for uncleared swaps (Margin Rule) and a rule imposing position limits (Position Limits Rule).

We qualify as a “non-financial entity” for purposes of the End-User Exception and, as such, we are eligible for such exception. As a result, our hedging activities are not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. We also qualify as a “non-financial end user” for purposes of the Margin Rule; therefore, our uncleared swaps are not subject to regulatory margin requirements. Finally, we believe our hedging activities constitute bona fide hedging under the Position Limits Rule and are therefore not subject to limitation under such rule. However, many of our hedge counterparties and many other market participants are not eligible for the End-User Exception, are subject to mandatory clearing and the Margin Rule for swaps with some or all of their other swap counterparties, and are subject to the Position Limits Rule. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations related to derivatives (collectively, Foreign Regulations) which apply to our transactions with counterparties subject to such Foreign Regulations.

The Dodd-Frank Act, the rules adopted thereunder and the Foreign Regulations could increase the cost of derivative contracts, alter the terms of derivative contracts, reduce the availability of derivatives to protect against the price risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, lessen the number of available counterparties and, in turn, increase our exposure to less creditworthy counterparties. If our use of derivatives is reduced as a result of the Dodd-Frank Act, related regulations or the Foreign Regulations, our results of operations may become more volatile, and our cash flows may be less predictable, which could adversely affect our ability to plan for, and fund, our capital expenditure requirements. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

Risks Related to COVID-19, Cybersecurity and Other External Factors

Outbreaks of communicable diseases can adversely affect our business, financial condition and results of operations.

Global or national health concerns, including a widespread outbreak of contagious disease, can, among other impacts, negatively impact the global economy, reduce demand and pricing for crude oil, NGLs and natural gas, lead to operational disruptions and limit our ability to execute on our business plan, any of which could materially and adversely affect our business, financial condition and results of operations. Furthermore, uncertainty regarding the impact of any outbreak of contagious disease could lead to increased volatility in crude oil, NGLs and natural gas prices.

For example, the current pandemic involving a highly transmissible and pathogenic coronavirus (COVID-19) and the measures being taken to address and limit the spread of the virus have adversely affected the economies and financial markets of the world, resulting in an economic downturn that negatively impacted global demand and prices for crude oil, NGLs and natural gas. In fact, the substantial declines in crude oil, NGLs and natural gas prices that occurred in the first half of 2020 as a result of the economic downturn and overall reduction of demand prompted by the COVID-19 pandemic (and the oversupply of crude oil from certain foreign oil-exporting countries) materially and adversely affected the amount of cash flows we had available for our 2020 capital expenditures and other operating expenses, our results of operations during the first half of 2020 and the trading price of our common stock.

While the prices for crude oil, NGLs and natural gas have since recovered to at or above pre-pandemic levels, if such price declines were to reoccur and continue for an extended period of time, our cash flows and results of operations would be further adversely affected, as could the trading price of our common stock. For further discussion regarding the potential impacts on us of lower commodity prices and extended declines in commodity prices, see the related discussion in the first risk factor in this section.

Further, if the COVID-19 outbreak should worsen, we may also experience disruptions to commodities markets, equipment supply chains and the availability of our workforce, which could materially and adversely affect our ability to conduct our business and operations. In addition, if the COVID-19 outbreak were to worsen, resulting in another economic downturn, our customers and other contractual parties may be unable to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, and may be unable to access the credit and capital markets for such purposes. Such inability of our customers and other contractual counterparties may materially and adversely affect our business, financial condition, results of operations and cash flows.

There are still too many variables and uncertainties regarding the COVID-19 pandemic, including the duration and severity of the outbreak; the emergence, contagiousness and threat of new and different strains of the virus; the development, availability, acceptance, and effectiveness of treatments or vaccines; the extent of travel restrictions, business closures and other measures imposed by governmental authorities; disruptions in the supply chain; a prolonged delay in the resumption of operations by one or more contractual parties; an increasingly competitive labor market due to a sustained labor shortage or increased turnover caused by the COVID-19 pandemic; increased logistics costs; additional operating costs due to remote working arrangements, adherence to social distancing guidelines, and other COVID-19-related challenges; increased risk of cyberattacks on information technology systems used in remote working arrangements; increased privacy-related risks due to processing health-related personal information; absence of employees due to illness; the impact of the pandemic on EOG's customers and contractual counterparties; and other factors that are currently unknown or considered immaterial, to fully assess the potential impact on our business, financial condition and results of operations.

Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, we face various security threats, including (i) cybersecurity threats to gain unauthorized access to, or control of, our sensitive information or to render our data or systems corrupted or unusable; (ii) threats to the security of our facilities and infrastructure or to the security of third-party facilities and infrastructure, such as gathering, transportation, processing, fractionation, refining and export facilities; and (iii) threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material and adverse effect on our business.

We rely extensively on information technology systems, including internally developed software, data hosting platforms, real-time data acquisition systems, third-party software, cloud services and other internally or externally hosted hardware and software platforms, to (i) estimate our oil and gas reserves, (ii) process and record financial and operating data, (iii) process and analyze all stages of our business operations, including exploration, drilling, completions, production, transportation, pipelines and other related activities and (iv) communicate with our employees and vendors, suppliers and other third parties. Further, our reliance on technology has increased due to the increased use of personal devices, remote communications and other work-from-home practices in response to the COVID-19 pandemic. Although we have implemented and invested in, and will continue to implement and invest in, controls, procedures and protections (including internal and external personnel) that are designed to protect our systems, identify and remediate on a regular basis vulnerabilities in our systems and related infrastructure and monitor and mitigate the risk of data loss and other cybersecurity threats, such measures cannot entirely eliminate cybersecurity threats and the controls, procedures and protections we have implemented and invested in may prove to be ineffective.

Our systems and networks, and those of our business associates, may become the target of cybersecurity attacks, including, without limitation, denial-of-service attacks; malicious software; data privacy breaches by employees, insiders or others with authorized access; cyber or phishing-attacks; ransomware; attempts to gain unauthorized access to our data and systems; and other electronic security breaches. If any of these security breaches were to occur, we could suffer disruptions to our normal operations, including our drilling, completion, production and corporate functions, which could materially and adversely affect us in a variety of ways, including, but not limited to, the following:

- unauthorized access to, and release of, our business data, reserves information, strategic information or other sensitive or proprietary information, which could have a material and adverse effect on our ability to compete for oil and gas resources, or reduce our competitive advantage over other companies;
- data corruption, communication interruption, or other operational disruptions during our drilling activities, which could result in our failure to reach the intended target or a drilling incident;
- data corruption or operational disruptions of our production-related infrastructure, which could result in loss of production or accidental discharges;
- unauthorized access to, and release of, personal information of our royalty owners, employees and vendors, which could expose us to allegations that we did not sufficiently protect such information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt our operations;
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could result in reduced demand for our production or delay or prevent us from transporting and marketing our production, in either case resulting in a loss of revenues;
- a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- a deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties;
- a cybersecurity attack on a communications network or power grid, which could cause operational disruptions resulting in a loss of revenues; and
- a cybersecurity attack on our automated and surveillance systems, which could cause a loss of production and potential environmental hazards.

Further, strategic targets, such as energy-related assets, may be at a greater risk of terrorist attacks or cybersecurity attacks than other targets in the United States. Moreover, external digital technologies control nearly all of the crude oil and natural gas distribution and refining systems in the U.S. and abroad, which are necessary to transport and market our production. A cybersecurity attack directed at, for example, crude oil and natural gas distribution systems could (i) damage critical distribution and storage assets or the environment; (ii) disrupt energy supplies and markets, by delaying or preventing delivery of production to markets; and (iii) make it difficult or impossible to accurately account for production and settle transactions.

Any such terrorist attack or cybersecurity attack that affects us, our customers, suppliers, or others with whom we do business and/or energy-related assets could have a material adverse effect on our business, including disruption of our operations, damage to our reputation, a loss of counterparty trust, reimbursement or other costs, increased compliance costs, significant litigation exposure and legal liability or regulatory fines, penalties or intervention. Although we have business continuity plans in place, our operations may be adversely affected by significant and widespread disruption to our systems and the infrastructure that supports our business. While we continue to evolve and modify our business continuity plans as well as our cyber threat detection and mitigation systems, there can be no assurance that they will be effective in avoiding disruption and business impacts. Further, our insurance may not be adequate to compensate us for all resulting losses, and the cost to obtain adequate coverage may increase for us in the future and some insurance coverage may become more difficult to obtain, if available at all.

While we have experienced limited cybersecurity incidents in the past, we have not had, to date, any business interruptions or material losses from breaches of cybersecurity. However, there is no assurance that we will not suffer any such interruptions or losses in the future. Further, as technologies evolve and cybersecurity threats become more sophisticated, we are continually expending additional resources to modify or enhance our security measures to protect against such threats and to identify and remediate on a regular basis any vulnerabilities in our information systems and related infrastructure that may be detected, and these expenditures in the future may be significant. Additionally, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, which could require us to expend significant additional resources to meet such requirements.

Terrorist activities and military and other actions could materially and adversely affect us.

Terrorist attacks and the threat of terrorist attacks (including cyber-related attacks), whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. The U.S. government has from time to time issued public warnings that indicate that energy-related assets, such as transportation and refining facilities, might be specific targets of terrorist organizations.

Any such actions and the threat of such actions, including any resulting political instability or societal disruption, could materially and adversely affect us in unpredictable ways, including, but not limited to, the disruption of energy supplies and markets, the reduction of overall demand for crude oil and natural gas, increased volatility in crude oil and natural gas prices or the possibility that the facilities and other infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

Weather and climate may have a significant and adverse impact on us.

Demand for crude oil and natural gas is, to a degree, dependent on weather and climate, which impacts, among other things, the price we receive for the commodities that we produce and, in turn, our cash flows and results of operations. For example, relatively warm temperatures during a winter season generally result in relatively lower demand for natural gas (as less natural gas is used to heat residences and businesses) and, as a result, lower prices for natural gas production during that season.

In addition, there has been public discussion that climate change may be associated with more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather events, such as winter storms, flooding and tropical storms and hurricanes in the Gulf of Mexico, which may cause a loss of production from temporary cessation of activity or damaged facilities and equipment. Such extreme weather events could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs, the installation and operation of gathering, processing, compression, storage, transportation and/or export facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression, storage and transportation services and export services. Such extreme weather events and changes in weather patterns may materially and adversely affect our business and, in turn, our financial condition and results of operations.

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates and discussions of EOG's net proved reserves of crude oil and condensate, natural gas liquids (NGLs) and natural gas, the qualifications of the preparers of EOG's reserve estimates, EOG's independent petroleum consultants and EOG's processes and controls with respect to its reserve estimates, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in "Supplemental Information to Consolidated Financial Statements" represent only estimates. Reserve engineering is a complex, subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates by different engineers normally vary. In addition, results of drilling, testing and production or fluctuations in commodity prices subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. Further, the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

In general, the rate of production from crude oil and natural gas properties declines as reserves are produced. Except to the extent EOG acquires additional properties containing proved reserves, conducts successful exploration, exploitation and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, the proved reserves of EOG will decline as reserves are produced. Future production is, therefore, highly dependent upon the level of success of these activities. For related discussion, see ITEM 1A, Risk Factors. EOG's estimates of reserves filed with other federal agencies are consistent with the information set forth in "Supplemental Information to Consolidated Financial Statements."

Acreage. The following table summarizes EOG's gross and net developed and undeveloped acreage at December 31, 2021 (in thousands). Excluded is acreage in which EOG's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2,329	1,829	2,852	1,864	5,181	3,693
Trinidad	80	67	216	125	296	192
Oman	—	—	4,585	4,585	4,585	4,585
Australia	—	—	1,009	1,009	1,009	1,009
Total	2,409	1,896	8,662	7,583	11,071	9,479

Most of our undeveloped oil and gas leases, particularly in the United States, are subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. Approximately 0.2 million net acres will expire in 2022, 0.1 million net acres will expire in 2023 and 0.1 million net acres will expire in 2024 if production is not established or we take no other action to extend the terms of the leases or obtain concessions. As of December 31, 2021, there were no proved undeveloped reserves (PUDs) associated with such undeveloped acreage. In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

Many of our oil and gas leases are large enough to accommodate more than one producing unit. Included in our undeveloped acreage is non-producing acreage within such larger producing leases.

Acreage associated with EOG's exploration program in Oman was reduced as of December 31, 2021, due to EOG contractually agreeing with its partner in Block 49 to withdraw. Additionally, EOG does not intend to proceed with additional work commitments and therefore anticipates relinquishing its Block 36 acreage in the third quarter of 2022.

The agreement governing the acreage associated with our exploration program in offshore Australia is set to expire at various dates through 2025 depending on EOG's decision to move forward with its defined work program or unless EOG is granted a production license.

Productive Well Summary. The following table represents EOG's gross and net productive wells, including 2,427 wells in which we hold a royalty interest.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	8,999	6,402	4,756	2,850	13,755	9,252
Trinidad	2	2	33	26	35	28
Total ⁽¹⁾	9,001	6,404	4,789	2,876	13,790	9,280

(1) EOG operated 10,233 gross and 9,064 net producing crude oil and natural gas wells at December 31, 2021. Gross crude oil and natural gas wells include 129 wells with multiple completions.

Drilling and Acquisition Activities. During the years ended December 31, 2021, 2020 and 2019, EOG expended \$4.0 billion, \$3.7 billion and \$6.6 billion, respectively, for exploratory and development drilling, facilities and acquisition of leases and producing properties, including asset retirement costs of \$127 million, \$117 million and \$186 million, respectively. The following tables set forth the results of the gross crude oil and natural gas wells completed for the years ended December 31, 2021, 2020 and 2019:

	Gross Development Wells Completed				Gross Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2021								
United States	474	72	5	551	10	1	1	12
Trinidad	—	—	—	—	—	—	—	—
Oman	—	—	—	—	—	—	3	3
Total	474	72	5	551	10	1	4	15
2020								
United States	580	13	15	608	3	—	4	7
Trinidad	—	—	—	—	—	3	—	3
Total	580	13	15	608	3	3	4	10
2019								
United States	833	26	14	873	4	—	1	5
Trinidad	—	1	—	1	—	—	1	1
China	—	2	—	2	—	—	1	1
Total	833	29	14	876	4	—	3	7

The following tables set forth the results of the net crude oil and natural gas wells completed for the years ended December 31, 2021, 2020 and 2019:

	Net Development Wells Completed				Net Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2021								
United States	434	66	4	504	10	1	1	12
Trinidad	—	—	—	—	—	—	—	—
Oman	—	—	—	—	—	—	3	3
Total	434	66	4	504	10	1	4	15
2020								
United States	516	12	15	543	2	—	3	5
Trinidad	—	—	—	—	—	2	—	2
Total	516	12	15	543	2	2	3	7
2019								
United States	721	22	12	755	4	—	1	5
Trinidad	—	1	—	1	—	—	1	1
China	—	2	—	2	—	—	1	1
Total	721	25	12	758	4	—	3	7

EOG participated in the drilling of wells that were in the process of being drilled or completed at the end of the period as set out in the table below for the years ended December 31, 2021, 2020 and 2019:

	Wells in Progress at End of Period					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
United States	191	167	155	147	317	286
Trinidad	1	1	1	1	1	1
China	—	—	3	3	3	3
Oman	—	—	1	1	—	—
Total	192	168	160	152	321	290

Included in the previous table of wells in progress at the end of the period were wells which had been drilled, but were not completed (DUCs). In order to effectively manage its capital expenditures and to provide flexibility in managing its drilling rig and well completion schedules, EOG, from time to time, will have an inventory of DUCs. At December 31, 2021, there were approximately 72 MMBoe of net PUDs associated with EOG's inventory of DUCs. Under EOG's current drilling plan, all such DUCs are expected to be completed within five years from the original booking date of such reserves. The following table sets forth EOG's DUCs, for which PUDs had been booked, as of the end of each period.

	Drilled Uncompleted Wells at End of Period					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
United States	121	105	89	86	188	165
China	—	—	3	3	3	3
Total	121	105	92	89	191	168

EOG acquired wells as set forth in the following table (excluding the acquisition of additional interests in 5, 8 and 11 net wells in which EOG previously owned an interest for the years ended December 31, 2021, 2020 and 2019, respectively) for the years ended December 31, 2021, 2020 and 2019:

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2021						
United States	2	14	16	1	13	14
Total	2	14	16	1	13	14
2020						
United States	80	3	83	70	3	73
Total	80	3	83	70	3	73
2019						
United States	9	45	54	9	37	46
Total	9	45	54	9	37	46

Other Property, Plant and Equipment. EOG's other property, plant and equipment primarily includes gathering, transportation and processing infrastructure assets and buildings which support EOG's exploration and production activities. EOG does not own drilling rigs, hydraulic fracturing equipment or rail cars. All of EOG's drilling and completion activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors.

ITEM 3. *Legal Proceedings*

See the information set forth under the "Contingencies" caption in Note 8 of the Notes to Consolidated Financial Statements, which is incorporated by reference herein.

Item 103 of Regulation S-K promulgated under the Securities Exchange Act of 1934, as amended, requires disclosure regarding certain proceedings arising under federal, state or local environmental laws when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that EOG reasonably believes will exceed a specified threshold. Pursuant to this item, EOG uses a threshold of \$1 million for purposes of determining whether disclosure of any such proceedings is required; EOG believes proceedings under this threshold are not material to EOG's business and financial condition. Applying this threshold, there are no environmental proceedings to disclose for the quarter and year ended December 31, 2021.

ITEM 4. *Mine Safety Disclosures*

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

PART II

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

EOG's common stock is traded on the New York Stock Exchange under the ticker symbol "EOG."

As of February 11, 2022, there were approximately 2,000 record holders and approximately 749,000 beneficial owners of EOG's common stock.

EOG expects to continue to pay dividends to its stockholders; however, EOG's Board may reduce the dividend or cease declaring dividends at any time, including if it determines that EOG's current or forecasted future cash flows provided by its operating activities (after deducting capital expenditures and other commitments) are not sufficient to pay EOG's desired levels of dividends to its stockholders or to pay dividends to its stockholders at all. For additional discussion, see ITEM 1A, Risk Factors.

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	(a) Total Number of Shares Purchased ⁽¹⁾	(b) Average Price Paid per Share	(c) Total Number of Shares or Value of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs ⁽²⁾⁽³⁾
October 1, 2021 - October 31, 2021	40,557	\$ 89.42	—	6,386,200
November 1, 2021 - November 30, 2021	22,852	94.24	—	\$ 5,000,000,000
December 1, 2021 - December 31, 2021	15,351	86.38	—	\$ 5,000,000,000
Total	78,760	\$ 90.22		

- (1) The 78,760 total shares for the quarter ended December 31, 2021, and the 503,667 total shares for the full year 2021, consist solely of shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock, restricted stock unit or performance unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against either the September 2001 Authorization or the November 2021 Authorization (each as defined and further discussed below).
- (2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock (September 2001 Authorization). The September 2001 Authorization was announced on October 2, 2001. EOG did not repurchase any shares under the September 2001 Authorization during the fourth quarter 2021 (through November 3, 2021) and last repurchased shares under the September 2001 Authorization in March 2003.
- (3) Effective November 4, 2021, the Board (i) established a new share repurchase authorization to allow for the repurchase by EOG of up to \$5 billion of its common stock (November 2021 Authorization) and (ii) revoked and terminated the September 2001 Authorization. Under the November 2021 Authorization (which was announced November 4, 2021), EOG may repurchase shares from time to time, at management's discretion, in accordance with applicable securities laws, including through open market transactions, privately negotiated transactions or any combination thereof. The timing and amount of repurchases, if any, will be at the discretion of EOG's management and will depend on a variety of factors, including the then-trading price of EOG's common stock, corporate and regulatory requirements, and other market and economic conditions. Repurchased shares will be held as treasury shares and will be available for general corporate purposes. The November 2021 Authorization has no time limit, does not require EOG to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board at any time. EOG did not repurchase any shares under the November 2021 Authorization during the period from November 4, 2021 through December 31, 2021.

Comparative Stock Performance

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically requests that such information be treated as "soliciting material" or specifically incorporates such information by reference into such a filing.

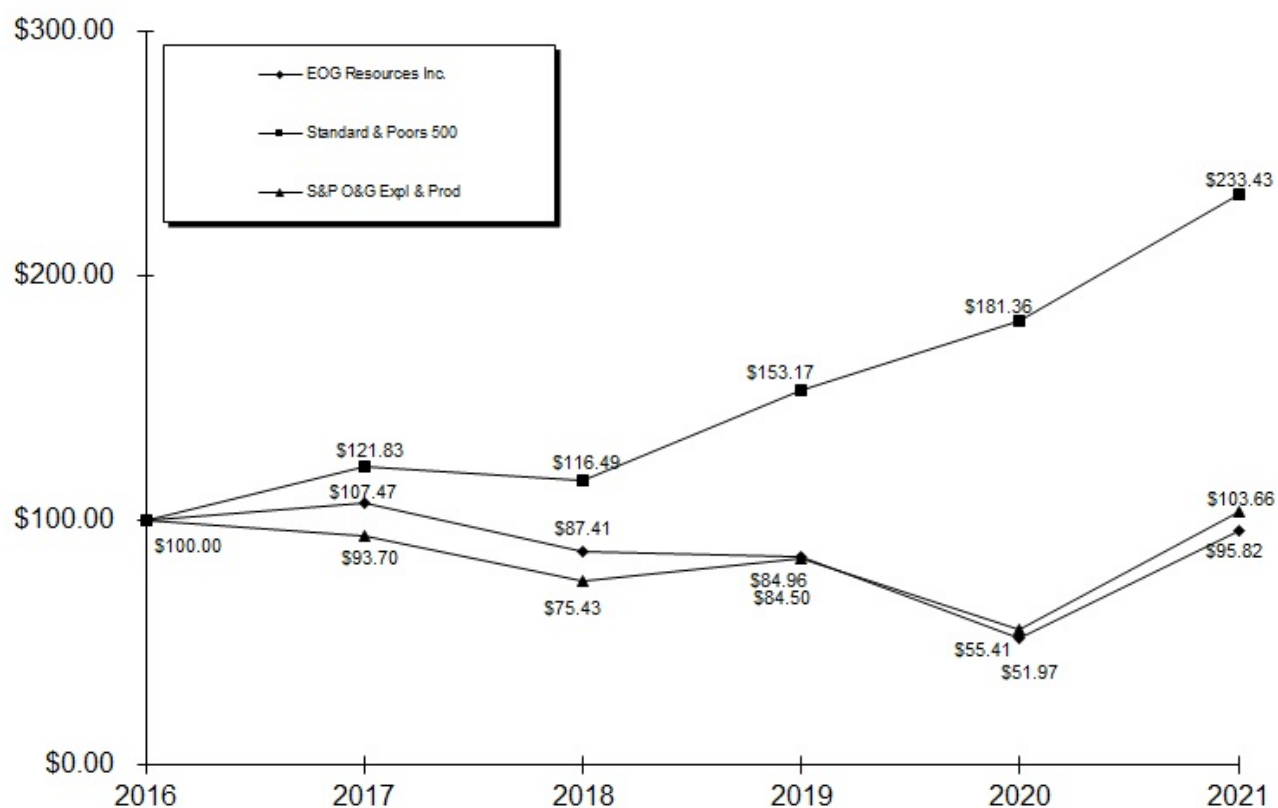
The performance graph shown below compares the cumulative five-year total return to stockholders on EOG's common stock as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index (S&P 500) and the Standard and Poor's 500 Oil & Gas Exploration & Production Index (S&P O&G E&P). The comparison was prepared based upon the following assumptions:

1. \$100 was invested on December 31, 2016 in each of the following: common stock of EOG, the S&P 500 and the S&P O&G E&P.
2. Dividends are reinvested.

Comparison of Five-Year Cumulative Total Returns

EOG, S&P 500 and S&P O&G E&P

(Performance Results Through December 31, 2021)



	2016	2017	2018	2019	2020	2021
EOG	\$ 100.00	\$ 107.47	\$ 87.41	\$ 84.96	\$ 51.97	\$ 95.82
S&P 500	\$ 100.00	\$ 121.83	\$ 116.49	\$ 153.17	\$ 181.36	\$ 233.43
S&P O&G E&P	\$ 100.00	\$ 93.70	\$ 75.43	\$ 84.50	\$ 55.41	\$ 103.66

ITEM 6. Reserved

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) crude oil and natural gas companies in the United States with proved reserves in the United States and Trinidad. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. Pursuant to this strategy, each prospective drilling location is evaluated by its estimated rate of return. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term growth in shareholder value and maintain a strong balance sheet. EOG implements its strategy primarily by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure, coupled with efficient and safe operations and robust environmental stewardship practices and performance, is integral in the implementation of EOG's strategy.

EOG realized net income of \$4,664 million during 2021 as compared to a net loss of \$605 million for 2020. At December 31, 2021, EOG's total estimated net proved reserves were 3,747 million barrels of oil equivalent (MMBoe), an increase of 527 MMBoe from December 31, 2020. During 2021, net proved crude oil and condensate and natural gas liquids (NGLs) reserves increased by 50 million barrels (MMBbl), and net proved natural gas reserves increased by 2,862 billion cubic feet or 477 MMBoe, in each case from December 31, 2020.

Recent Developments

Commodity Prices. In 2020, the COVID-19 pandemic and the measures taken to address and limit the spread of the virus adversely affected the economies and financial markets of the world, resulting in an economic downturn beginning in early 2020 that negatively impacted global demand and prices for crude oil and condensate, NGLs and natural gas. In response, OPEC+, a consortium of OPEC (Organization of Petroleum Exporting Countries) and certain non-OPEC global producers (Russia, Kazakhstan and others), agreed to voluntarily curtail crude oil supplies beginning in April 2020 with a schedule to bring back some of these curtailments through April 2021. Certain other non-OPEC+ countries also curtailed production and/or reduced investments in existing and new crude oil projects. This response started the process of balancing supply with demand.

In 2021, the effects of global COVID-19 mitigation efforts, including extensive global fiscal stimulus and the availability of vaccines, tempered by new COVID-19 variant strains and corresponding containment measures in certain parts of the world, have resulted in overall increased demand for crude oil and condensate, NGLs and natural gas. See ITEM 1A, Risk Factors for discussion of risks related to the COVID-19 pandemic.

During 2021 and into early 2022, OPEC+ continued their schedule of gradually returning all curtailed production through 2022 in response to expected increases in demand for crude oil. The continuing rebalancing of crude oil demand and supply resulting from improving or stabilizing conditions in certain economies and financial markets of the world, combined with the continuing actions taken by OPEC+, had a positive impact on crude oil prices in 2021. Prices for crude oil and condensate and NGLs returned to prepandemic levels in the first quarter of 2021, while natural gas prices returned to prepandemic levels at the beginning of 2021.

As a result of the many uncertainties associated with (i) the world economic and political environment, (ii) the COVID-19 pandemic and its continuing effect on the economies and financial markets of the world and (iii) any future actions by the members of OPEC+, and the effect of these uncertainties on worldwide supplies of, and demand for, crude oil and condensate, NGLs and natural gas, EOG is unable to predict what changes may occur in crude oil and condensate, NGLs and natural gas prices in the future. However, prices for crude oil and condensate, NGLs and natural gas have historically been volatile, and this volatility is expected to continue. For related discussion, see ITEM 1A, Risk Factors.

EOG will continue to monitor future market conditions and adjust its capital allocation strategy and production outlook accordingly in order to maximize shareholder value while maintaining its strong financial position.

Climate Change. For a discussion of climate change matters and related regulatory matters, including potential developments related to climate change and the potential impacts and risks of such developments on EOG, see ITEM 1A, Risk Factors, and the related discussion in ITEM 1, Business – Regulation. EOG will continue to monitor and assess any climate change-related developments that could impact EOG and the oil and gas industry, to determine the impact on its business and operations, and take appropriate actions where necessary.

Operations

Several important developments have occurred since January 1, 2021.

United States. EOG's efforts to identify plays with large reserve potential have proven to be successful. EOG continues to drill numerous wells in large acreage plays, which in the aggregate have contributed substantially to, and are expected to continue to contribute substantially to, EOG's crude oil and condensate, NGLs and natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise to unconventional crude oil and, to a lesser extent, liquids-rich natural gas plays.

During 2021, EOG continued to focus on increasing drilling, completion and operating efficiencies gained in prior years. Such efficiencies resulted in lower operating, drilling and completion costs in 2021. In addition, EOG continued to evaluate certain potential crude oil and condensate, NGLs and natural gas exploration and development prospects and to look for opportunities to add drilling inventory through leasehold acquisitions, farm-ins, exchanges or tactical acquisitions. On a volumetric basis, as calculated using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas, crude oil and condensate and NGLs production accounted for approximately 75% and 76% of United States production during 2021 and 2020, respectively. During 2021, drilling and completion activities occurred primarily in the Delaware Basin play, Eagle Ford oil play and Rocky Mountain area. EOG's major producing areas in the United States are in Texas and New Mexico. EOG faced interruptions to sales in certain markets due to disruptions throughout the United States from Winter Storm Uri in the first quarter of 2021. Winter Storm Uri also negatively impacted Lease and Well, Transportation and Gathering and Processing Costs in the first quarter of 2021. See ITEM 1, Business - Exploration and Production for further discussion regarding EOG's 2021 United States operations.

Trinidad. In the Republic of Trinidad and Tobago (Trinidad), EOG continues to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium Block, Modified U(a) Block, Block 4(a), Modified U(b) Block, the Banyan Field and the Sercan Area have been developed and are producing natural gas, which is sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary, and crude oil and condensate which is sold to Heritage Petroleum Company Limited (Heritage).

In March 2021, EOG signed a farmout agreement with Heritage, which allows EOG to earn a 65% working interest in a portion of the contract area (EOG Area) governed by the Trinidad Northern Area License. The EOG Area is located offshore the southwest coast of Trinidad. EOG continues to make progress on the design and fabrication of a platform and related facilities for its previously announced discovery in the Modified U(a) Block.

In 2022, EOG expects to drill one net exploratory well in the EOG Area in addition to three development wells and one exploratory well in the Modified U(a) Block.

Other International. In Australia, on April 22, 2021, a subsidiary of EOG entered into a purchase and sale agreement to acquire a 100% interest in the WA-488-P Block, located offshore Western Australia. The transaction was closed in the fourth quarter of 2021 including the transfer of the petroleum exploration permit for that block. In 2022, EOG will continue preparing for the drilling of an exploration well which is expected to commence in 2023.

In the Sultanate of Oman (Oman), a Royal Decree was issued on March 9, 2021, and EOG became a participant in the Exploration and Production Sharing Agreement for Block 49, holding a 50% working interest. EOG's partner in Block 49 completed the drilling and testing of one net exploratory well, which was determined to be a dry hole. EOG notified its partner and the Ministry of Energy and Minerals of its intention to withdraw from Block 49. In Block 36, where EOG holds a 100% working interest, EOG drilled two net exploratory wells and completed one net exploratory well. There was a discovery of natural gas in Block 36, but the well results did not yield sufficient projected returns for EOG to move forward with the project. EOG recorded pretax impairment charges of \$45 million and dry hole costs of \$42 million in 2021. In 2022, EOG expects to exit Block 36.

In May 2021, EOG closed the sale of its subsidiary which held all of its assets in the China Sichuan Basin (China). Net production was approximately 25 million cubic feet per day (MMcfd) of natural gas prior to the sale. EOG no longer has any operations or assets in China.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States, primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas reserves have been identified.

Capital Structure

One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 19% at December 31, 2021 and 22% at December 31, 2020. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

On February 1, 2021, EOG repaid upon maturity the \$750 million aggregate principal amount of its 4.100% Senior Notes due 2021 (2021 Notes).

During 2021, EOG funded \$4.1 billion (\$124 million of which was non-cash) in exploration and development and other property, plant and equipment expenditures (excluding asset retirement obligations), paid \$2,684 million in dividends to common stockholders and repaid the 2021 Notes, primarily by utilizing net cash provided from its operating activities and net proceeds of \$231 million from the sale of assets.

Total anticipated 2022 capital expenditures are estimated to range from approximately \$4.3 billion to \$4.7 billion, excluding acquisitions and non-cash transactions. The majority of 2022 expenditures will be focused on United States crude oil drilling activities. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program, bank borrowings, borrowings under its senior unsecured revolving credit facility, joint development agreements and similar agreements and equity and debt offerings.

Management continues to believe EOG has one of the strongest prospect inventories in EOG's history. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer incremental exploration and/or production opportunities.

Dividend Declarations and Share Repurchase Authorization. On February 25, 2021, EOG's Board increased the quarterly cash dividend on the common stock from the previous \$0.375 per share to \$0.4125 per share, effective beginning with the dividend paid on April 30, 2021, to stockholders of record as of April 16, 2021.

On May 6, 2021, EOG's Board declared a special cash dividend on the common stock of \$1.00 per share. The special cash dividend, which was in addition to the quarterly cash dividend, was paid on July 30, 2021 to stockholders of record as of July 16, 2021.

On November 4, 2021, EOG's Board (i) further increased the quarterly cash dividend on the common stock from the previous \$0.4125 per share to \$0.75 per share, effective beginning with the dividend paid on January 28, 2022, to stockholders of record as of January 14, 2022, (ii) declared a special cash dividend on the common stock of \$2.00 per share, paid on December 30, 2021, to stockholders of record as of December 15, 2021, (iii) established a new share repurchase authorization to allow for the repurchase by EOG of up to \$5 billion of the common stock and (iv) revoked and terminated the share repurchase authorization established by the Board in September 2001. See ITEM 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities for additional discussion.

On February 24, 2022, the Board declared a quarterly cash dividend on the common stock of \$0.75 per share payable April 29, 2022, to stockholders of record as of April 15, 2022. The Board also declared a special dividend of \$1.00 per share payable March 29, 2022, to stockholders of record as of March 15, 2022.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2021, should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning on page F-1.

Operating Revenues and Other

During 2021, operating revenues increased \$7,610 million, or 69%, to \$18,642 million from \$11,032 million in 2020. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, NGLs and natural gas, increased \$8,090 million, or 111%, to \$15,381 million in 2021 from \$7,291 million in 2020. Revenues from the sales of crude oil and condensate and NGLs in 2021 were approximately 84% of total wellhead revenues compared to 89% in 2020. During 2021, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of \$1,152 million compared to net gains of \$1,145 million in 2020. Gathering, processing and marketing revenues increased \$1,705 million during 2021, to \$4,288 million from \$2,583 million in 2020. EOG recognized net gains on asset dispositions of \$17 million in 2021 compared to net losses on asset dispositions of \$47 million in 2020.

Wellhead volume and price statistics for the years ended December 31, 2021, 2020 and 2019 were as follows:

Year Ended December 31	2021	2020	2019
Crude Oil and Condensate Volumes (MBbld) ⁽¹⁾			
United States	443.4	408.1	455.5
Trinidad	1.5	1.0	0.6
Other International ⁽²⁾	0.1	0.1	0.1
Total	445.0	409.2	456.2
Average Crude Oil and Condensate Prices (\$/Bbl) ⁽³⁾			
United States	\$ 68.54	\$ 38.65	\$ 57.74
Trinidad	56.26	30.20	47.16
Other International ⁽²⁾	42.36	43.08	57.40
Composite	68.50	38.63	57.72
Natural Gas Liquids Volumes (MBbld) ⁽¹⁾			
United States	144.5	136.0	134.1
Other International ⁽²⁾	—	—	—
Total	144.5	136.0	134.1
Average Natural Gas Liquids Prices (\$/Bbl) ⁽³⁾			
United States	\$ 34.35	\$ 13.41	\$ 16.03
Other International ⁽²⁾	—	—	—
Composite	34.35	13.41	16.03
Natural Gas Volumes (MMcfd) ⁽¹⁾			
United States	1,210	1,040	1,069
Trinidad	217	180	260
Other International ⁽²⁾	9	32	37
Total	1,436	1,252	1,366
Average Natural Gas Prices (\$/Mcf) ⁽³⁾			
United States	\$ 4.88	\$ 1.61	\$ 2.22
Trinidad	3.40	2.57	2.72
Other International ⁽²⁾	5.67	4.66	4.44
Composite	4.66	1.83	2.38
Crude Oil Equivalent Volumes (MBoed) ⁽⁴⁾			
United States	789.6	717.5	767.8
Trinidad	37.7	30.9	44.0
Other International ⁽²⁾	1.6	5.4	6.2
Total	828.9	753.8	818.0
Total MMBoe ⁽⁴⁾	302.5	275.9	298.6

(1) Thousand barrels per day or million cubic feet per day, as applicable.

(2) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, NGLs and natural gas. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

2021 compared to 2020. Wellhead crude oil and condensate revenues in 2021 increased \$5,339 million, or 92%, to \$11,125 million from \$5,786 million in 2020, due primarily to a higher composite average wellhead crude oil and condensate price (\$4,852 million) and an increase in production (\$487 million). EOG's composite wellhead crude oil and condensate price for 2021 increased 77% to \$68.50 per barrel compared to \$38.63 per barrel in 2020. Wellhead crude oil and condensate production in 2021 increased 9% to 445 MBbld as compared to 409 MBbld in 2020. The increased production was primarily in the Permian Basin, partially offset by decreased production in the Eagle Ford oil play.

NGLs revenues in 2021 increased \$1,144 million, or 171%, to \$1,812 million from \$668 million in 2020 primarily due to a higher composite average wellhead NGLs price (\$1,104 million) and an increase in production (\$40 million). EOG's composite average wellhead NGLs price increased 156% to \$34.35 per barrel in 2021 compared to \$13.41 per barrel in 2020. NGL production in 2021 increased 6% to 145 MBbld as compared to 136 MBbld in 2020. The increased production was primarily in the Permian Basin.

Wellhead natural gas revenues in 2021 increased \$1,607 million, or 192%, to \$2,444 million from \$837 million in 2020, primarily due to a higher composite wellhead natural gas price (\$1,486 million) and an increase in natural gas deliveries (\$121 million). EOG's composite average wellhead natural gas price increased 155% to \$4.66 per Mcf in 2021 compared to \$1.83 per Mcf in 2020. Natural gas deliveries in 2021 increased 15% to 1,436 MMcfd as compared to 1,252 MMcfd in 2020. The increase in production was primarily due to increased production of associated natural gas from the Permian Basin and higher natural gas volumes in Trinidad, partially offset by lower natural gas volumes associated with the dispositions of the Marcellus Shale assets in the third quarter of 2020 and the China assets in the second quarter of 2021.

During 2021, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of \$1,152 million, which included net cash paid for settlements of crude oil, NGL and natural gas financial derivative contracts of \$638 million. During 2020, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$1,145 million, which included net cash received from settlements of crude oil, NGL and natural gas financial derivative contracts of \$1,071 million.

Gathering, processing and marketing revenues are revenues generated from sales of third-party crude oil, NGLs and natural gas, as well as fees associated with gathering third-party natural gas and revenues from sales of EOG-owned sand. Purchases and sales of third-party crude oil and natural gas may be utilized in order to balance firm capacity at third-party facilities with production in certain areas and to utilize excess capacity at EOG-owned facilities. EOG sells sand in order to balance the timing of firm purchase agreements with completion operations. Marketing costs represent the costs to purchase third-party crude oil, natural gas and sand and the associated transportation costs, as well as costs associated with EOG-owned sand sold to third parties.

Gathering, processing and marketing revenues less marketing costs in 2021 increased \$230 million compared to 2020, primarily due to higher margins on crude oil and condensate and natural gas marketing activities. The margin on crude oil marketing activities in 2020 was negatively impacted by the price decline for crude oil in inventory awaiting delivery to customers and EOG's decision early in the second quarter of 2020 to reduce commodity price volatility by selling May and June 2020 deliveries under fixed price arrangements.

2020 compared to 2019. Wellhead crude oil and condensate revenues in 2020 decreased \$3,827 million, or 40%, to \$5,786 million from \$9,613 million in 2019, due primarily to a lower composite average wellhead crude oil and condensate price (\$2,860 million) and a decrease in production (\$967 million). EOG's composite wellhead crude oil and condensate price for 2020 decreased 33% to \$38.63 per barrel compared to \$57.72 per barrel in 2019. Wellhead crude oil and condensate production in 2020 decreased 10% to 409 MBbld as compared to 456 MBbld in 2019. The decreased production was primarily in the Eagle Ford oil play and the Rocky Mountain area, partially offset by increased production in the Permian Basin.

NGLs revenues in 2020 decreased \$116 million, or 15%, to \$668 million from \$784 million in 2019 primarily due to a lower composite average wellhead NGLs price (\$130 million), partially offset by an increase in production (\$13 million). EOG's composite average wellhead NGLs price decreased 16% to \$13.41 per barrel in 2020 compared to \$16.03 per barrel in 2019. NGL production in 2020 increased 1% to 136 MBbld as compared to 134 MBbld in 2019. The increased production was primarily in the Permian Basin, partially offset by decreased production of associated NGLs in the Eagle Ford oil play.

Wellhead natural gas revenues in 2020 decreased \$347 million, or 29%, to \$837 million from \$1,184 million in 2019, primarily due to a lower composite wellhead natural gas price (\$251 million) and a decrease in natural gas deliveries (\$96 million). EOG's composite average wellhead natural gas price decreased 23% to \$1.83 per Mcf in 2020 compared to \$2.38 per Mcf in 2019. Natural gas deliveries in 2020 decreased 8% to 1,252 MMcfd as compared to 1,366 MMcfd in 2019. The decrease in production was primarily due to lower natural gas volumes in Trinidad, the Marcellus Shale and the Rocky Mountain area, partially offset by increased production of associated natural gas from the Permian Basin.

During 2020, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$1,145 million, which included net cash received for settlements of crude oil, NGL and natural gas financial derivative contracts of \$1,071 million. During 2019, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of \$180 million, which included net cash received for settlements of crude oil and natural gas financial derivative contracts of \$231 million.

Gathering, processing and marketing revenues less marketing costs in 2020 decreased \$124 million compared to 2019, primarily due to lower margins on crude oil and condensate marketing activities. The margin on crude oil marketing activities in 2020 was negatively impacted by the price decline for crude oil in inventory awaiting delivery to customers and EOG's decision early in the second quarter of 2020 to reduce commodity price volatility by selling May and June 2020 deliveries under fixed price arrangements.

Operating and Other Expenses

2021 compared to 2020. During 2021, operating expenses of \$12,540 million were \$964 million higher than the \$11,576 million incurred during 2020. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2021 and 2020:

	2021	2020
Lease and Well	\$ 3.75	\$ 3.85
Transportation Costs	2.85	2.66
Gathering and Processing Costs	1.85	1.66
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	11.58	11.85
Other Property, Plant and Equipment	0.49	0.47
General and Administrative (G&A)	1.69	1.75
Net Interest Expense	0.59	0.74
Total ⁽¹⁾	\$ 22.80	\$ 22.98

(1) Total excludes exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, gathering and processing costs, DD&A, G&A and net interest expense for 2021 compared to 2020 are set forth below. See "Operating Revenues and Other" above for a discussion of production volumes.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain crude oil and natural gas wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses of \$1,135 million in 2021 increased \$72 million from \$1,063 million in 2020 primarily due to higher operating and maintenance costs in the United States (\$33 million) and in Trinidad (\$5 million), higher workovers expenditures in the United States (\$25 million) and higher lease and well administrative expenses in the United States (\$12 million); partially offset by lower operating and maintenance costs in Canada (\$6 million) and as a result of the disposition of all of the China assets in the second quarter of 2021 (\$5 million). Lease and well expenses increased in the United States primarily due to increased operating activities resulting from increased production.

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease or an aggregation point on EOG's gathering system to a downstream point of sale. Transportation costs include transportation fees, storage and terminal fees, the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), the cost of dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees and fuel costs.

Transportation costs of \$863 million in 2021 increased \$128 million from \$735 million in 2020 primarily due to increased transportation costs in the Permian Basin (\$121 million) and the Rocky Mountain area (\$22 million), partially offset by decreased transportation costs in the Eagle Ford oil play (\$13 million).

Gathering and processing costs represent operating and maintenance expenses and administrative expenses associated with operating EOG's gathering and processing assets as well as natural gas processing fees and certain NGLs fractionation fees paid to third parties. EOG pays third parties to process the majority of its natural gas production to extract NGLs.

Gathering and processing costs increased \$100 million to \$559 million in 2021 compared to \$459 million in 2020 primarily due to increased gathering and processing fees related to production from the Permian Basin (\$51 million) and the Rocky Mountain area (\$10 million), increased operating costs in the Permian Basin (\$26 million) and the Rocky Mountain area (\$7 million) and increased administrative expenses in the United States (\$15 million); partially offset by decreased gathering and processing fees in the Eagle Ford oil play (\$5 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual DD&A group calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells and reserve revisions (upward or downward) primarily related to well performance, economic factors and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from period to period. DD&A of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses in 2021 increased \$251 million to \$3,651 million from \$3,400 million in 2020. DD&A expenses associated with oil and gas properties in 2021 were \$235 million higher than in 2020 primarily due to an increase in production in the United States (\$307 million) and Trinidad (\$12 million) and higher unit rates in Trinidad (\$14 million), partially offset by lower unit rates in the United States (\$85 million). Unit rates in the United States decreased primarily due to upward reserve revisions and reserves added at lower costs as a result of increased efficiencies. DD&A expenses associated with other property, plant and equipment in 2021 were \$15 million higher than in 2020 primarily due to an increase in expense related to storage assets.

G&A expenses of \$511 million in 2021 increased \$27 million from \$484 million in 2020 primarily due to a net increase in costs associated with corporate support activities, including employee-related expenses and increased information system costs (\$54 million); partially offset by a decrease in idle equipment and termination fees (\$46 million).

Net interest expense of \$178 million in 2021 was \$27 million lower than 2020 primarily due to repayment in February 2021 of the \$750 million aggregate principal amount of 4.100% Senior Notes due 2021 (\$29 million), repayment in June 2020 of the \$500 million aggregate principal amount of 4.40% Senior Notes due 2020 (\$9 million), repayment in April 2020 of the \$500 million aggregate principal amount of 2.45% Senior Notes due 2020 (\$3 million) and lower interest payments for late royalty payments on Oklahoma properties (\$6 million), partially offset by the issuance in April 2020 of the \$750 million aggregate principal amount of 4.950% Senior Notes due 2050 (\$11 million) and \$750 million aggregate principal amount of 4.375% Senior Notes due 2030 (\$10 million).

Exploration costs of \$154 million in 2021 increased \$8 million from \$146 million in 2020 primarily due to increased geological and geophysical expenditures in the United States.

Impairments include: amortization of unproved oil and gas property costs as well as impairments of proved oil and gas properties; other property, plant and equipment; and other assets. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a DD&A group level to the unamortized capitalized cost of the group. If the expected undiscounted future cash flows, based on EOG's estimates of (and assumptions regarding) future crude oil, NGLs and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by using the Income Approach described in the Fair Value Measurement Topic of the Financial Accounting Standards Board's Accounting Standards Codification (ASC). In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

The following table represents impairments for the years ended December 31, 2021 and 2020 (in millions):

	<u>2021</u>	<u>2020</u>
Proved properties	\$ 20	\$ 1,268
Unproved properties	310	472
Other assets	28	300
Inventories	13	—
Firm commitment contracts	5	60
Total	<u>\$ 376</u>	<u>\$ 2,100</u>

Impairments of proved properties in 2020 were primarily due to the decline in commodity prices and were primarily related to the write-down to fair value of legacy and non-core natural gas, crude oil and combo plays in the United States. Impairments of unproved oil and gas properties included charges of \$38 million in 2021 due to the decision in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman and \$252 million in 2020 for certain leasehold costs that are no longer expected to be developed before expiration. Impairments of other assets in 2020 were primarily for the write-down to fair value of sand and crude-by-rail assets and a commodity price-related write-down of other assets. Impairments of firm commitment contracts in 2020 were a result of the decision to exit the Horn River Basin in Canada.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are generally determined based on wellhead revenues, and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

Taxes other than income in 2021 increased \$569 million to \$1,047 million (6.8% of wellhead revenues) from \$478 million (6.6% of wellhead revenues) in 2020. The increase in taxes other than income was primarily due to increased severance/production taxes in the United States (\$522 million), increased severance/production taxes in Trinidad (\$7 million) and decreased state severance tax refunds (\$39 million).

EOG recognized an income tax provision of \$1,269 million in 2021 compared to an income tax benefit of \$134 million in 2020, primarily due to increased pretax income. The net effective tax rate for 2021 increased to 21% from 18% in 2020. The higher effective tax rate is mostly due to taxes attributable to EOG's foreign operations and stock-based compensation tax deficiencies increasing the effective tax rate on pretax income in 2021 and decreasing the effective tax rate on pretax loss in 2020.

2020 compared to 2019. During 2020, operating expenses of \$11,576 million were \$2,105 million lower than the \$13,681 million incurred during 2019. The following table presents the costs per Boe for the years ended December 31, 2020 and 2019:

	<u>2020</u>	<u>2019</u>
Lease and Well	\$ 3.85	\$ 4.58
Transportation Costs	2.66	2.54
Gathering and Processing Costs	1.66	1.60
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	11.85	12.25
Other Property, Plant and Equipment	0.47	0.31
General and Administrative (G&A)	1.75	1.64
Net Interest Expense	0.74	0.62
Total ⁽¹⁾	<u>\$ 22.98</u>	<u>\$ 23.54</u>

(1) Total excludes exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, gathering and processing costs, DD&A, G&A and net interest expense for 2020 compared to 2019 are set forth below. See "Operating Revenues and Other" above for a discussion of production volumes.

Lease and well expenses of \$1,063 million in 2020 decreased \$304 million from \$1,367 million in 2019 primarily due to lower operating and maintenance costs in the United States (\$157 million) and in Canada (\$25 million), lower workovers expenditures in the United States (\$103 million) and lower lease and well administrative expenses in the United States (\$12 million). Lease and well expenses decreased in the United States primarily due to decreased operating activities resulting from decreased production, efficiency improvements and service cost reductions.

Transportation costs of \$735 million in 2020 decreased \$23 million from \$758 million in 2019 primarily due to decreased transportation costs in the Fort Worth Basin Barnett Shale (\$27 million), the Rocky Mountain area (\$24 million) and the Eagle Ford oil play (\$20 million), partially offset by increased transportation costs in the Permian Basin (\$56 million).

Gathering and processing costs decreased \$20 million to \$459 million in 2020 compared to \$479 million in 2019 primarily due to decreased operating costs in the Eagle Ford (\$16 million) and decreased gathering and processing fees in the Eagle Ford oil play (\$9 million) and the Fort Worth Basin Barnett Shale (\$5 million); partially offset by increased gathering and processing fees in the Permian Basin (\$15 million).

DD&A expenses in 2020 decreased \$350 million to \$3,400 million from \$3,750 million in 2019. DD&A expenses associated with oil and gas properties in 2020 were \$390 million lower than in 2019 primarily due to a decrease in production in the United States (\$222 million) and Trinidad (\$22 million) and lower unit rates in the United States (\$150 million). Unit rates in the United States decreased primarily due to upward reserve revisions and reserves added at lower costs as a result of increased efficiencies. DD&A expenses associated with other property, plant and equipment in 2020 were \$40 million higher than in 2019 primarily due to an increase in expense related to gathering and storage assets and equipment.

G&A expenses of \$484 million in 2020 decreased \$5 million from \$489 million in 2019 primarily due to decreased employee-related expenses (\$43 million) and professional and other services (\$7 million), partially offset by idle equipment and termination fees (\$46 million).

Net interest expense of \$205 million in 2020 was \$20 million higher than 2019 primarily due to the issuance of the Notes in April 2020 (\$51 million) and lower capitalized interest (\$7 million), partially offset by repayment in June 2019 of the \$900 million aggregate principal amount of 5.625% Senior Notes due 2019 (\$21 million), repayment in June 2020 of the \$500 million aggregate principal amount of 4.40% Senior Notes due 2020 (\$13 million) and repayment in April 2020 of the \$500 million aggregate principal amount of 2.45% Senior Notes due 2020 (\$10 million).

Exploration costs of \$146 million in 2020 increased \$6 million from \$140 million in 2019 primarily due to increased geological and geophysical expenditures in the United States (\$15 million), partially offset by decreased general and administrative expenses in the United States (\$8 million).

The following table represents impairments for the years ended December 31, 2020 and 2019 (in millions):

	<u>2020</u>	<u>2019</u>
Proved properties	\$ 1,268	\$ 207
Unproved properties	472	220
Other assets	300	91
Firm commitment contracts	60	—
Total	<u>\$ 2,100</u>	<u>\$ 518</u>

Impairments of proved properties were primarily due to the write-down to fair value of legacy and non-core natural gas and crude oil and combo plays in 2020 and legacy natural gas assets in 2019.

Taxes other than income in 2020 decreased \$322 million to \$478 million (6.6% of wellhead revenues) from \$800 million (6.9% of wellhead revenues) in 2019. The decrease in taxes other than income was primarily due to decreased severance/production taxes in the United States (\$232 million), decreased ad valorem/property taxes in the United States (\$51 million) and a state severance tax refund (\$27 million).

Other income, net, was \$10 million in 2020 compared to other income, net, of \$31 million in 2019. The decrease of \$21 million in 2020 was primarily due to a decrease in interest income.

In response to the economic impacts of the COVID-19 pandemic, the President of the United States signed the Coronavirus Aid, Relief, and Economic Security Act (the CARES Act) into law on March 27, 2020. The CARES Act provides economic support to individuals and businesses through enhanced loan programs, expanded unemployment benefits, and certain payroll and income tax relief, among other provisions. The primary tax benefit of the CARES Act for EOG was the acceleration of approximately \$150 million of additional refundable alternative minimum tax (AMT) credits into tax year 2019. These credits originated from AMT paid by EOG in years prior to 2018 and were reflected as a deferred tax asset and a non-current receivable as of December 31, 2019 since they had been expected to either offset future current tax liabilities or be refunded on a declining balance schedule through 2021. The \$150 million of additional refundable AMT credits was received in July 2020.

Further pandemic relief was contained in the Consolidated Appropriations Act of 2021 (the CA Act) which was signed into law by the President of the United States on December 27, 2020. In addition, the CA Act provided government funding and limited corporate income tax relief primarily related to making permanent or extending certain tax provisions, none of which were a material benefit for EOG.

EOG recognized an income tax benefit of \$134 million in 2020 compared to an income tax provision of \$810 million in 2019, primarily due to decreased pretax income. The net effective tax rate for 2020 decreased to 18% from 23% in 2019. The lower effective tax rate is mostly due to taxes attributable to EOG's foreign operations and increased stock-based compensation tax deficiencies.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2021, were funds generated from operations, net proceeds from the issuance of long-term debt, net cash received from settlements of commodity derivative contracts and proceeds from asset sales. The primary uses of cash were funds used in operations; exploration and development expenditures; dividend payments to stockholders; repayments of debt; net cash paid for settlements of commodity derivative contracts and other property, plant and equipment expenditures.

2021 compared to 2020. Net cash provided by operating activities of \$8,791 million in 2021 increased \$3,783 million from \$5,008 million in 2020 primarily due to an increase in wellhead revenues (\$8,090 million) and an increase in gathering, processing and marketing revenues less marketing costs (\$230 million); partially offset by an increase in net cash paid for settlements of commodity derivative contracts (\$1,709 million); an increase in net cash paid for income taxes (\$1,320 million); net cash used in working capital in 2021 (\$817 million) compared to net cash provided by working capital in 2020 (\$193 million); and an increase in cash operating expenses (\$882 million).

Net cash used in investing activities of \$3,419 million in 2021 increased by \$71 million from \$3,348 million in 2020 primarily due to an increase in additions to oil and gas properties (\$394 million), partially offset by net cash provided by working capital associated with investing activities in 2021 (\$200 million) compared to net cash used in working capital associated with investing activities in 2020 (\$75 million); an increase in proceeds from the sales of assets (\$39 million); and a decrease in additions to other property, plant and equipment (\$9 million).

Net cash used in financing activities of \$3,493 million in 2021 included cash dividend payments (\$2,684 million), repayments of long-term debt (\$750 million), purchases of treasury stock in connection with stock compensation plans (\$41 million) and repayment of finance lease liabilities (\$37 million). Cash provided by financing activities in 2021 included proceeds from stock options exercised and employee stock purchase plan activity (\$19 million).

2020 compared to 2019. Net cash provided by operating activities of \$5,008 million in 2020 decreased \$3,155 million from \$8,163 million in 2019 primarily due to a decrease in wellhead revenues (\$4,291 million); unfavorable changes in working capital and other assets and liabilities (\$166 million); a decrease in gathering, processing and marketing revenues less marketing costs (\$123 million) and an increase in net cash paid for income taxes (\$86 million); partially offset by an increase in cash received for settlements of commodity derivative contracts (\$840 million) and a decrease in cash operating expenses (\$641 million).

Net cash used in investing activities of \$3,348 million in 2020 decreased by \$2,829 million from \$6,177 million in 2019 primarily due to a decrease in additions to oil and gas properties (\$2,908 million); an increase in proceeds from the sale of assets (\$52 million); a decrease in additions to other property, plant and equipment (\$49 million); and a decrease in other investing activities (\$10 million); partially offset by an unfavorable change in working capital associated with investing activities (\$190 million).

Net cash used in financing activities of \$359 million in 2020 included repayments of long-term debt (\$1,000 million), cash dividend payments (\$821 million), repayment of finance lease liabilities (\$19 million) and purchases of treasury stock in connection with stock compensation plans (\$16 million). Cash provided by financing activities in 2020 included long-term debt borrowings (\$1,484 million) and proceeds from stock options exercised and employee stock purchase plan activity (\$16 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2021, 2020 and 2019 (in millions):

	2021	2020	2019
Expenditure Category			
Capital			
Exploration and Development Drilling	\$ 2,864	\$ 2,664	\$ 4,951
Facilities	405	347	629
Leasehold Acquisitions ⁽¹⁾	215	265	276
Property Acquisitions ⁽²⁾	100	135	380
Capitalized Interest	33	31	38
Subtotal	<u>3,617</u>	<u>3,442</u>	<u>6,274</u>
Exploration Costs	154	146	140
Dry Hole Costs	71	13	28
Exploration and Development Expenditures	<u>3,842</u>	<u>3,601</u>	<u>6,442</u>
Asset Retirement Costs	127	117	186
Total Exploration and Development Expenditures	<u>3,969</u>	<u>3,718</u>	<u>6,628</u>
Other Property, Plant and Equipment ⁽³⁾	286	395	272
Total Expenditures	<u>\$ 4,255</u>	<u>\$ 4,113</u>	<u>\$ 6,900</u>

(1) Leasehold acquisitions included \$45 million, \$197 million and \$98 million related to non-cash property exchanges in 2021, 2020 and 2019, respectively.

(2) Property acquisitions included \$5 million, \$15 million and \$52 million related to non-cash property exchanges in 2021, 2020 and 2019, respectively.

(3) Other property, plant and equipment included non-cash additions of \$74 million and \$174 million, primarily related to finance lease transactions for storage facilities in 2021 and 2020, respectively.

Exploration and development expenditures of \$3,842 million for 2021 were \$241 million higher than the prior year. The increase was primarily due to increased exploration and development drilling expenditures in the United States (\$267 million) and increased facilities expenditures (\$58 million), partially offset by decreased exploration and development drilling expenditures in Trinidad (\$61 million), decreased leasehold acquisitions (\$50 million) and decreased property acquisitions (\$35 million). The 2021 exploration and development expenditures of \$3,842 million included \$3,172 million in development drilling and facilities, \$537 million in exploration, \$100 million in property acquisitions and \$33 million in capitalized interest. The 2020 exploration and development expenditures of \$3,601 million included \$2,905 million in development drilling and facilities, \$530 million in exploration, \$135 million in property acquisitions and \$31 million in capitalized interest. The 2019 exploration and development expenditures of \$6,442 million included \$5,513 million in development drilling and facilities, \$511 million in exploration, \$380 million in property acquisitions and \$38 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other economic factors. EOG believes it has significant flexibility and availability with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Commodity Derivative Transactions

Presented below is a comprehensive summary of EOG's financial commodity derivative contracts settled during the year ended December 31, 2021 (closed) and remaining for 2022 and thereafter, as of February 18, 2022. Crude oil and NGL volumes are presented in MBbld and prices are presented in \$/Bbl. Natural gas volumes are presented in MMBtu per day (MMBtud) and prices are presented in dollars per MMBtu (\$/MMBtu).

Crude Oil Financial Price Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price (\$/Bbl)
January 2021 (closed)	NYMEX West Texas Intermediate (WTI)	151	\$ 50.06
February - March 2021 (closed)	NYMEX WTI	201	51.29
April - June 2021 (closed)	NYMEX WTI	150	51.68
July - September 2021 (closed)	NYMEX WTI	150	52.71
January 2022 (closed)	NYMEX WTI	140	65.58
February - March 2022	NYMEX WTI	140	65.58
April - June 2022	NYMEX WTI	140	65.62
July - September 2022	NYMEX WTI	140	65.59
October - December 2022	NYMEX WTI	140	65.68
January - March 2023	NYMEX WTI	150	67.92
April - June 2023	NYMEX WTI	120	67.79
July - September 2023	NYMEX WTI	100	70.15
October - December 2023	NYMEX WTI	69	69.41

Crude Oil Basis Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price Differential (\$/Bbl)
February 2021 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	30	\$ 0.11
March - December 2021 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	125	0.17
January - February 2022 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	125	0.15
March - December 2022	NYMEX WTI Roll Differential ⁽¹⁾	125	0.15

(1) This settlement index is used to fix the differential in pricing between the NYMEX calendar month average and the physical crude oil delivery month.

NGL Financial Price Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price (\$/Bbl)
January - December 2021 (closed)	Mont Belvieu Propane (non-Tet)	15	\$ 29.44

Natural Gas Financial Price Swap Contracts

Period	Settlement Index	Contracts Sold		Contracts Purchased	
		Volume (MMBtud in thousands)	Weighted Average Price (\$/MMBtu)	Volume (MMBtud in thousands)	Weighted Average Price (\$/MMBtu)
January - March 2021 (closed)	NYMEX Henry Hub	500	\$ 2.99	500	\$ 2.43
April - September 2021 (closed)	NYMEX Henry Hub	500	2.99	570	2.81
October - December 2021 (closed)	NYMEX Henry Hub	500	2.99	500	2.83
January - December 2022 (closed) ⁽¹⁾	NYMEX Henry Hub	20	2.75	—	—
January - February 2022 (closed)	NYMEX Henry Hub	725	3.57	—	—
March - December 2022	NYMEX Henry Hub	725	3.57	—	—
January - December 2023	NYMEX Henry Hub	725	3.18	—	—
January - December 2024	NYMEX Henry Hub	725	3.07	—	—
January - December 2025	NYMEX Henry Hub	725	3.07	—	—
April - September 2021 (closed)	Japan Korea Marker (JKM)	70	6.65	—	—

(1) In January 2021, EOG executed the early termination provision granting EOG the right to terminate all of its 2022 natural gas price swap contracts which were open at that time. EOG received net cash of \$0.6 million for the settlement of these contracts.

Natural Gas Basis Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MMBtud in thousands)	Weighted Average Price (\$/MMBtu)
January - February 2022 (closed)	NYMEX Henry Hub Houston Ship Channel (HSC) Differential ⁽¹⁾	210	\$ (0.01)
March - December 2022	NYMEX Henry Hub HSC Differential ⁽¹⁾	210	(0.01)
January - December 2023	NYMEX Henry Hub HSC Differential ⁽¹⁾	135	(0.01)
January - December 2024	NYMEX Henry Hub HSC Differential ⁽¹⁾	10	0.00
January - December 2025	NYMEX Henry Hub HSC Differential ⁽¹⁾	10	0.00

(1) This settlement index is used to fix the differential between pricing at the Houston Ship Channel and NYMEX Henry Hub prices.

In connection with its financial commodity derivative contracts, EOG had \$1.4 billion of collateral posted at February 18, 2022. EOG expects this collateral to be applied to the settlement of financial commodity derivative contracts if market prices remain above contract prices or returned to EOG if market prices decrease below contract prices.

Financing

EOG's debt-to-total capitalization ratio was 19% at December 31, 2021, compared to 22% at December 31, 2020. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

At December 31, 2021 and 2020, respectively, EOG had outstanding \$4,890 million and \$5,640 million aggregate principal amount of senior notes which had estimated fair values of \$5,577 million and \$6,505 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable inputs regarding interest rates available to EOG at year-end. EOG's debt is at fixed interest rates. While changes in interest rates affect the fair value of EOG's senior notes, such changes do not expose EOG to material fluctuations in earnings or cash flow.

During 2021, EOG funded its capital program and operations primarily by utilizing cash provided by operating activities, cash on hand and proceeds from asset sales. While EOG maintains a \$2.0 billion revolving credit facility to back its commercial paper program, there were no borrowings outstanding at any time during 2021 and the amount outstanding at year-end was zero. EOG considers the availability of its \$2.0 billion senior unsecured revolving credit facility, as described in Note 2 to Consolidated Financial Statements, to be sufficient to meet its ongoing operating needs.

Foreign Currency Exchange Rate Risk

During 2021, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Trinidad, Australia, Oman, Canada and, through May 2021, in China. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against foreign currency exchange rate risk.

Outlook

Pricing. Crude oil, NGLs and natural gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world economic and political environment, worldwide supplies of, and demand for, crude oil and condensate, NGLs and natural gas, the availabilities of other energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in crude oil and condensate, NGLs, natural gas, ammonia and methanol prices in the future. The market price of crude oil and condensate, NGLs and natural gas in 2022 will impact the amount of cash generated from EOG's operating activities, which will in turn impact EOG's financial position. As of February 18, 2022, the average 2022 NYMEX crude oil and natural gas prices were \$84.45 per barrel and \$4.61 per MMBtu, respectively, representing an increase of 24% for crude oil and an increase of 20% for natural gas from the average NYMEX prices in 2021. See ITEM 1A, Risk Factors for additional discussion of the impact of commodity prices (including fluctuations in commodity prices) on our financial condition, cash flows and results of operations.

Including the impact of EOG's crude oil and NGL derivative contracts (exclusive of basis swaps) and based on EOG's tax position, EOG's price sensitivity in 2022 for each \$1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately \$107 million for net income and \$138 million for pretax cash flows from operating activities. Including the impact of EOG's natural gas derivative contracts and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2022 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each \$0.10 per Mcf increase or decrease in wellhead natural gas price is approximately \$15 million for net income and \$19 million for pretax cash flows from operating activities. For information regarding EOG's crude oil, NGLs and natural gas financial commodity derivative contracts through February 18, 2022, see "Commodity Derivative Transactions" above.

Capital. EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States. In particular, EOG will be focused on United States drilling activity in its Delaware Basin, Eagle Ford oil play, Rocky Mountain area and Dorado gas play where it generates its highest rates-of-return. To further enhance the economics of these plays, EOG expects to continue to improve well performance and offset inflationary pressure through efficiency gains and by locking in certain service costs for drilling and completion activities. In addition, EOG expects to spend a portion of its anticipated 2022 capital expenditures on leasing acreage, evaluating new prospects, long-term transportation infrastructure and environmental projects.

The total anticipated 2022 capital expenditures of approximately \$4.3 billion to \$4.7 billion, excluding acquisitions and non-cash transactions, is structured to maintain EOG's strategy of capital discipline by funding its exploration, development and exploitation activities primarily from available internally generated cash flows and cash on hand. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program, bank borrowings, borrowings under its \$2.0 billion senior unsecured revolving credit facility and equity and debt offerings.

Operations. In 2022, total crude oil, NGLs and natural gas production is expected to return to prepandemic levels. In 2022, EOG expects to continue to focus on mitigating inflationary pressure on operating costs through efficiency improvements.

Cash Requirements. Certain of EOG's capital expenditures and operating expenses are subject to contracts with minimum commitments, including those that meet the definition of a lease under ASU 2016-02. In 2022, EOG anticipates the following cash requirements under these commitments (in millions):

Finance Leases ⁽¹⁾	\$	42
Operating Leases ⁽¹⁾		262
Leases Effective, Not Commenced ⁽¹⁾		25
Transportation and Storage Service Commitments ⁽²⁾⁽³⁾		961
Purchase and Service Obligations ⁽³⁾		374
Total Cash Requirements	\$	1,664

(1) For more information on contracts that meet the definition of a lease under ASU 2016-02, see Note 18 to Consolidated Financial Statements.

(2) Amounts exclude transportation and storage service commitments that meet the definition of a lease. Amounts shown are based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars into United States dollars at December 31, 2021. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results of operations of EOG.

(3) For more information on transportation and storage service commitments and purchase and service obligations, see Note 8 to Consolidated Financial Statements.

In 2022, EOG has no senior notes maturing and expects to pay interest of \$191 million on senior notes. For more information on EOG's current and long-term debt, see Note 2 to Consolidated Financial Statements.

Cash requirements to settle the liability for unrecognized tax benefits, EOG's pension and postretirement benefit obligations and the liability for dismantlement, abandonment and asset retirement obligations (see Notes 6, 7, and 15, respectively, to Consolidated Financial Statements) are excluded because they are subject to estimates and the timing of settlement is unknown.

EOG expects to fund its exploration, development and exploitation activities and other cash requirements, both in 2022 and in future years, primarily from internally generated cash flows and cash on hand. As discussed above, EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program, bank borrowings, borrowings under its \$2.0 billion senior unsecured revolving credit facility and equity and debt offerings.

Summary of Critical Accounting Policies and Estimates

EOG prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. EOG identifies certain accounting policies and estimates as critical based on, among other things, their impact on EOG's financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting policies and estimates cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies and estimates. Following is a discussion of EOG's most critical accounting policies and estimates:

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves in accordance with United States Securities and Exchange Commission (SEC) regulations, which directly impact financial accounting estimates, including depreciation, depletion and amortization and impairments of proved properties and related assets. Proved reserves represent estimated quantities of crude oil and condensate, NGLs and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

The process of estimating quantities of proved oil and gas reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Proved reserves are estimated using a trailing 12-month average price, in accordance with SEC rules. Crude oil, NGLs and natural gas prices have exhibited significant volatility in the past, and EOG expects that volatility to continue in the future. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

Oil and Gas Exploration and Development Costs

EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered commercial quantities of proved reserves. If commercial quantities of proved reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether commercial quantities of proved reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the estimated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. The concept of sufficient progress is subject to significant judgment and may require further operational actions or require additional approvals from government agencies or partners in oil and gas operations, among other factors, the timing of which may delay management's determinations. See Note 16 to Consolidated Financial Statements.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of EOG's calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward or downward, earnings will increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the group. If the expected undiscounted future cash flows, based on EOG's estimates of (and assumptions regarding) future crude oil and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value. Estimates of undiscounted future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. In addition, such assumptions and estimates are reasonably likely to change in the future.

Crude oil, NGLs and natural gas prices have exhibited significant volatility in the past, and EOG expects that volatility to continue in the future. During the five years ended December 31, 2021, WTI crude oil spot prices have fluctuated from approximately \$(36.98) per barrel to \$85.64 per barrel, and Henry Hub natural gas spot prices have ranged from approximately \$1.33 per MMBtu to \$23.86 per MMBtu. Market prices for NGLs are influenced by the components extracted, including ethane, propane, butane and natural gasoline, among others, and the respective market pricing for each component.

EOG uses the five-year NYMEX futures strip for WTI crude oil and Henry Hub natural gas and the five-year Oil Price Information Services futures strip for NGLs components (in each case as of the applicable balance sheet date) as a basis to estimate future crude oil, NGLs and natural gas prices. EOG's proved reserves estimates, including the timing of future production, are also subject to significant assumptions and judgment, and are frequently revised (upwards and downwards) as more information becomes available. In the future, if any combination of crude oil prices, NGLs prices, natural gas prices or estimated proved reserves diverge negatively from EOG's current estimates, impairment charges may be necessary.

See Notes 13 and 14 to Consolidated Financial Statements for further disclosures of impairments of oil and gas properties and other assets.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate. Significant assumptions used in estimating future taxable income include future crude oil, NGLs and natural gas prices and levels of capital reinvestment. Changes in such assumptions or changes in tax laws and regulations could materially affect the recognized amounts of valuation allowances. See Note 6 to Consolidated Financial Statements.

Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, goals, returns and rates of return, budgets, reserves, levels of production, capital expenditures, costs and asset sales, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "aims," "ambition," "initiative," "goal," "may," "will," "focused on," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, generate returns and rates of return, replace or increase drilling locations, reduce or otherwise control operating costs and capital expenditures, generate cash flows, pay down or refinance indebtedness, achieve, reach or otherwise meet initiatives, plans, goals, ambitions or targets with respect to emissions, other environmental matters, safety matters or other ESG (environmental/social/governance) matters, or pay and/or increase dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids (NGLs), natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG is successful in its efforts to (i) economically develop its acreage in, (ii) produce reserves and achieve anticipated production levels and rates of return from, (iii) decrease or otherwise control its drilling, completion, operating and capital costs related to, and (iv) maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects and associated potential and existing drilling locations;
- the extent to which EOG is successful in its efforts to market its production of crude oil and condensate, NGLs and natural gas;
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, physical breaches of our facilities and other infrastructure or breaches of the information technology systems, facilities and infrastructure of third parties with which we transact business;
- the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, storage, transportation, refining, and export facilities;
- the availability, cost, terms and timing of issuance or execution of mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including climate change-related regulations, policies and initiatives (for example, with respect to air emissions); tax laws and regulations (including, but not limited to, carbon tax legislation); environmental, health and safety laws and regulations relating to disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations affecting the leasing of acreage and permitting for oil and gas drilling and the calculation of royalty payments in respect of oil and gas production; laws and regulations imposing additional permitting and disclosure requirements, additional operating restrictions and conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- the impact of climate change-related policies and initiatives at the corporate and/or investor community levels and other potential developments related to climate change, such as (but not limited to) changes in consumer and industrial/commercial behavior, preferences and attitudes with respect to the generation and consumption of energy; increased availability of, and increased consumer and industrial/commercial demand for, competing energy sources (including alternative energy sources); technological advances with respect to the generation, transmission, storage and consumption of energy; alternative fuel requirements; energy conservation measures; decreased demand for, and availability of, services and facilities related to the exploration for, and production of, crude oil, NGLs and natural gas; and negative perceptions of the oil and gas industry and, in turn, reputational risks associated with the exploration for, and production of, crude oil, NGLs and natural gas;

- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and drilling, completing and operating costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully, economically and in compliance with applicable laws and regulations;
- competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties;
- the availability and cost of, and competition in the oil and gas exploration and production industry for, employees and other personnel, facilities, equipment, materials (such as water and tubulars) and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression, storage, transportation, and export facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent to which EOG is successful in its completion of planned asset dispositions;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- the duration and economic and financial impact of epidemics, pandemics or other public health issues, including the COVID-19 pandemic;
- geopolitical factors and political conditions and developments around the world (such as the imposition of tariffs or trade or other economic sanctions, political instability and armed conflict), including in the areas in which EOG operates;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts; and
- the other factors described under ITEM 1A, Risk Factors of this Annual Report on Form 10-K and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the duration or extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

The information required by this Item is incorporated by reference from Item 7 of this report, specifically the information set forth under the captions "Commodity Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. *Financial Statements and Supplementary Data*

The information required by this Item is included in this report as set forth in the "Index to Financial Statements" on page F-1 and is incorporated by reference herein.

ITEM 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of December 31, 2021. EOG's disclosure controls and procedures are designed to provide reasonable assurance that information that is required to be disclosed in the reports EOG files or submits under the Exchange Act is accumulated and communicated to EOG's management, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the United States Securities and Exchange Commission. Based on that evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of December 31, 2021.

Management's Annual Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2021. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013)*. Based on this assessment and such criteria, EOG's management believes that EOG's internal control over financial reporting was effective as of December 31, 2021. See also "Management's Responsibility for Financial Reporting" appearing on page F-2 of this report, which is incorporated herein by reference.

The report of EOG's independent registered public accounting firm relating to the consolidated financial statements and effectiveness of internal control over financial reporting is set forth on page F-3 of this report.

There were no changes in EOG's internal control over financial reporting that occurred during the quarter ended December 31, 2021, that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

ITEM 9B. Other Information

None.

ITEM 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspection

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this Item is incorporated by reference from (i) EOG's Definitive Proxy Statement with respect to its 2022 Annual Meeting of Stockholders to be filed not later than April 30, 2022 and (ii) Item 1 of this report, specifically the information therein set forth under the caption "Information About Our Executive Officers."

Pursuant to Rule 303A.10 of the New York Stock Exchange and Item 406 of Regulation S-K promulgated under the Securities Exchange Act of 1934, as amended, EOG has adopted a Code of Business Conduct and Ethics for Directors, Officers and Employees (Code of Conduct) that applies to all EOG directors, officers and employees, including EOG's principal executive officer, principal financial officer and principal accounting officer. EOG has also adopted a Code of Ethics for Senior Financial Officers (Code of Ethics) that, along with EOG's Code of Conduct, applies to EOG's principal executive officer, principal financial officer, principal accounting officer and controllers.

You can access the Code of Conduct and Code of Ethics on the "Governance" page under "Investors" on EOG's website at www.eogresources.com, and any EOG stockholder who so requests may obtain a printed copy of the Code of Conduct and Code of Ethics by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose any amendments to the Code of Conduct or Code of Ethics, and any waivers with respect to the Code of Conduct or Code of Ethics granted to EOG's principal executive officer, principal financial officer, principal accounting officer, any of our controllers or any of our other employees performing similar functions, on its website at www.eogresources.com within four business days of the amendment or waiver. In such case, the disclosure regarding the amendment or waiver will remain available on EOG's website for at least 12 months after the initial disclosure. There have been no waivers granted with respect to EOG's Code of Conduct or Code of Ethics.

ITEM 11. *Executive Compensation*

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2022 Annual Meeting of Stockholders to be filed not later than April 30, 2022. The Compensation and Human Resources Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2022 Annual Meeting of Stockholders to be filed not later than April 30, 2022.

Equity Compensation Plan Information

Stock Plans Approved by EOG Stockholders. EOG's stockholders approved the EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (2021 Plan) at the 2021 Annual Meeting of Stockholders in April 2021. From and after the April 29, 2021 effective date of the 2021 Plan, no further grants have been (or will be) made from the Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Amended and Restated 2008 Plan).

The 2021 Plan provides for grants of stock options, SARs, restricted stock and restricted stock units and other stock-based awards, up to an aggregate maximum of 20 million shares of EOG common stock, plus any shares that were subject to outstanding awards under the Amended and Restated 2008 Plan as of April 29, 2021 that subsequently are canceled or forfeited, expire or are otherwise not issued or are settled in cash. Under the 2021 Plan, grants may be made to employees and non-employee members of EOG's Board of Directors (Board).

EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. The 2008 Plan provided for grants of stock options, SARs, restricted stock, restricted stock units, performance units and other stock-based awards to employees and non-employee members of EOG's Board. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), EOG's stockholders approved an amendment to the 2008 Plan, authorizing an additional 13.8 million shares of EOG common stock for grant under the plan. At the 2013 Annual Meeting of Stockholders in May 2013, EOG's stockholders approved the Amended and Restated 2008 Plan, authorizing an additional 31.0 million shares of EOG common stock for grant under the plan and extending the expiration date of the plan to May 2023.

Also at the 2010 Annual Meeting, an amendment to the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP) was approved to increase the shares available for grant by 2.0 million shares and extend the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG. The ESPP was originally approved by EOG's stockholders in 2001 and would have expired on July 1, 2011. At the 2018 Annual Meeting of Stockholders in April 2018, stockholders approved an amendment and restatement of the ESPP to (among other changes) increase the number of shares available for grant by 2.5 million shares and further extend the term of the ESPP to December 31, 2027, unless terminated earlier by its terms or by EOG.

Stock Plans Not Approved by EOG Stockholders. In December 2008, the Board approved the amendment and continuation of the 1996 Deferral Plan as the "EOG Resources, Inc. 409A Deferred Compensation Plan" (Deferral Plan). Under the Deferral Plan (as subsequently amended), payment of up to 50% of base salary and 100% of annual cash bonus, director's fees, vestings of restricted stock units granted to non-employee directors (and dividends credited thereon) under the 2008 Plan and the 2021 Plan and 401(k) refunds (as defined in the Deferral Plan) may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if shares of EOG common stock were purchased at the closing stock price on the date of deferral. Dividends are credited quarterly and treated as if reinvested in EOG common stock. Payment of the phantom stock account is made in actual shares of EOG common stock in accordance with the Deferral Plan and the individual's deferral election. A total of 540,000 shares of EOG common stock have been authorized by the Board and registered for issuance under the Deferral Plan. As of December 31, 2021, 401,535 phantom shares had been issued. The Deferral Plan is currently EOG's only stock plan that has not been approved by EOG's stockholders.

The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by EOG's stockholders and those plans not approved by EOG's stockholders, in each case as of December 31, 2021.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ⁽¹⁾	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity Compensation Plans Approved by EOG Stockholders	11,524,127 ⁽²⁾	\$ 84.37	19,079,181 ⁽³⁾
Equity Compensation Plans Not Approved by EOG Stockholders	300,920 ⁽⁴⁾	N/A	138,465 ⁽⁵⁾
Total	11,825,047	\$ 84.37	19,217,646

- (1) The weighted-average exercise price is calculated based solely on the exercise prices of the outstanding stock option and SAR grants and does not reflect (i) shares that will be issued upon the vesting of outstanding grants of restricted stock units or the vesting of outstanding grants of performance units and restricted stock units with performance-based conditions (collectively, performance units) or (ii) shares that will be issued in respect of issued and outstanding Deferral Plan phantom shares, all of which have no exercise price.
- (2) Amount includes (i) 9,968,540 outstanding stock option and SAR grants, (ii) 876,476 outstanding restricted stock units, for which shares of EOG common stock will be issued, on a one-for-one basis, upon the vesting of such grants, and (iii) 679,111 outstanding performance units and assumes, for purposes of this table, (A) the application of a 100% performance multiple upon the completion of each of the remaining performance periods in respect of such grants and (B) accordingly, the issuance, on a one-for-one basis, of an aggregate 679,111 shares of EOG common stock upon the vesting of such grants. As more fully discussed in Note 7 to Consolidated Financial Statements, upon the application of the relevant performance multiple at the completion of each of the remaining performance periods in respect of such grants, (A) a minimum of 0 and a maximum of 1,358,222 performance units could be outstanding and (B) accordingly, a minimum of 0 and a maximum of 1,358,222 shares of EOG common stock could be issued upon the vesting of such grants.
- (3) Consists of (i) 17,500,011 shares remaining available for issuance under the 2021 Plan and (ii) 1,579,170 shares remaining available for purchase under the ESPP. As noted above, from and after the April 29, 2021 effective date of the 2021 Plan, no further grants have been (or will be) made from the Amended and Restated 2008 Plan.
- (4) Consists of shares of EOG common stock to be issued in accordance with the Deferral Plan and participant deferral elections (i.e., in respect of the 300,920 phantom shares issued and outstanding under the Deferral Plan as of December 31, 2021).
- (5) Represents phantom shares that remain available for issuance under the Deferral Plan.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence*

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2022 Annual Meeting of Stockholders to be filed not later than April 30, 2022.

ITEM 14. *Principal Accounting Fees and Services*

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2022 Annual Meeting of Stockholders to be filed not later than April 30, 2022.

PART IV

ITEM 15. *Exhibits, Financial Statement Schedules*

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedule

See "Index to Financial Statements" set forth on page F-1.

(a)(3), (b) Exhibits

See pages E-1 through E-6 for a listing of the exhibits.

ITEM 16. *Form 10-K Summary*

None.

EOG RESOURCES, INC.
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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), were prepared by management, which is responsible for the integrity, objectivity and fair presentation of such financial statements. The statements have been prepared in conformity with generally accepted accounting principles in the United States of America and, accordingly, include some amounts that are based on the best estimates and judgments of management.

EOG's management is also responsible for establishing and maintaining adequate internal control over financial reporting as well as designing and implementing programs and controls to prevent and detect fraud. The system of internal control of EOG is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. This system consists of 1) entity level controls, including written policies and guidelines relating to the ethical conduct of business affairs, 2) general computer controls and 3) process controls over initiating, authorizing, recording, processing and reporting transactions. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

The adequacy of EOG's financial controls and the accounting principles employed by EOG in its financial reporting are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of EOG. Moreover, EOG's independent registered public accounting firm and internal auditors have full, free, separate and direct access to the Audit Committee and meet with the committee periodically to discuss accounting, auditing and financial reporting matters.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2021. In making this assessment, EOG used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013)*. These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment and those criteria, management believes that EOG maintained effective internal control over financial reporting as of December 31, 2021.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements of EOG and audit EOG's internal control over financial reporting and issue a report thereon. In the conduct of the audits, Deloitte & Touche LLP was given unrestricted access to all financial records and related data, including all minutes of meetings of stockholders, the Board of Directors and committees of the Board of Directors. Management believes that all representations made to Deloitte & Touche LLP during the audits were valid and appropriate. Their audits were made in accordance with the standards of the Public Company Accounting Oversight Board (United States). Their report appears on page F-3.

EZRA Y. YACOB
Chief Executive Officer

TIMOTHY K. DRIGGERS
*Executive Vice President and Chief
Financial Officer*

Houston, Texas
February 24, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of
EOG Resources, Inc.
Houston, Texas

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of EOG Resources, Inc. and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income (loss) and comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Gas Properties and Depletion – Crude Oil and Condensate, NGLs, and Natural Gas Reserves — Refer to Note 1 to the Financial Statements

Critical Audit Matter Description

The Company's capitalized costs of proved oil and natural gas properties are depleted using the units of production method based on estimated proved reserves. The development of the Company's estimated proved crude oil, NGLs and natural gas reserve volumes requires management to make significant estimates and assumptions. The Company's reserve engineers estimate crude oil, NGLs and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions could materially affect the Company's estimated reserve quantities and the amount of depletion. Proved oil and gas properties were \$23 billion as of December 31, 2021, net of accumulated depletion, and depletion was \$3.5 billion, for the year then ended.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's estimated proved crude oil, NGLs and natural gas reserve quantities, required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant estimates and assumptions related to crude oil, NGLs and natural gas reserve quantities included the following, among others:

- We tested the operating effectiveness of controls over the Company's estimation of proved crude oil, NGLs and natural gas reserve quantities.
- We evaluated the Company's estimated proved crude oil, NGLs and natural gas reserve quantities by:
 - Evaluating the experience, qualifications, and objectivity of the Company's reserve engineers and the independent petroleum consultants, including the methodologies used to estimate proved crude oil, NGLs and natural gas reserve quantities.
 - Comparing the Company's reserve volumes to those independently developed by the independent petroleum consultants.
 - Comparing the Company's reserve estimated future production to historical production volumes.
 - Assessing the reasonableness of the production volume decline curves by comparing to historical decline curve estimates.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2022

We have served as the Company's auditor since 2002.

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(In Millions, Except Per Share Data)

Year Ended December 31	2021	2020	2019
Operating Revenues and Other			
Crude Oil and Condensate	\$ 11,125	\$ 5,786	\$ 9,613
Natural Gas Liquids	1,812	668	785
Natural Gas	2,444	837	1,184
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	(1,152)	1,145	180
Gathering, Processing and Marketing	4,288	2,583	5,360
Gains (Losses) on Asset Dispositions, Net	17	(47)	124
Other, Net	108	60	134
Total	<u>18,642</u>	<u>11,032</u>	<u>17,380</u>
Operating Expenses			
Lease and Well	1,135	1,063	1,367
Transportation Costs	863	735	758
Gathering and Processing Costs	559	459	479
Exploration Costs	154	146	140
Dry Hole Costs	71	13	28
Impairments	376	2,100	518
Marketing Costs	4,173	2,698	5,352
Depreciation, Depletion and Amortization	3,651	3,400	3,750
General and Administrative	511	484	489
Taxes Other Than Income	1,047	478	800
Total	<u>12,540</u>	<u>11,576</u>	<u>13,681</u>
Operating Income (Loss)	<u>6,102</u>	<u>(544)</u>	<u>3,699</u>
Other Income, Net	<u>9</u>	<u>10</u>	<u>31</u>
Income (Loss) Before Interest Expense and Income Taxes	<u>6,111</u>	<u>(534)</u>	<u>3,730</u>
Interest Expense			
Incurred	211	236	223
Capitalized	(33)	(31)	(38)
Net Interest Expense	<u>178</u>	<u>205</u>	<u>185</u>
Income (Loss) Before Income Taxes	<u>5,933</u>	<u>(739)</u>	<u>3,545</u>
Income Tax Provision (Benefit)	<u>1,269</u>	<u>(134)</u>	<u>810</u>
Net Income (Loss)	<u><u>\$ 4,664</u></u>	<u><u>\$ (605)</u></u>	<u><u>\$ 2,735</u></u>
Net Income (Loss) Per Share			
Basic	<u>\$ 8.03</u>	<u>\$ (1.04)</u>	<u>\$ 4.73</u>
Diluted	<u>\$ 7.99</u>	<u>\$ (1.04)</u>	<u>\$ 4.71</u>
Average Number of Common Shares			
Basic	<u>581</u>	<u>579</u>	<u>578</u>
Diluted	<u>584</u>	<u>579</u>	<u>581</u>
Comprehensive Income (Loss)			
Net Income (Loss)	<u>\$ 4,664</u>	<u>\$ (605)</u>	<u>\$ 2,735</u>
Other Comprehensive Loss			
Foreign Currency Translation Adjustments	(1)	(7)	(3)
Other, Net of Tax	1	—	—
Other Comprehensive Loss	<u>—</u>	<u>(7)</u>	<u>(3)</u>
Comprehensive Income (Loss)	<u><u>\$ 4,664</u></u>	<u><u>\$ (612)</u></u>	<u><u>\$ 2,732</u></u>

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(In Millions, Except Share Data)

At December 31	2021	2020
ASSETS		
Current Assets		
Cash and Cash Equivalents	\$ 5,209	\$ 3,329
Accounts Receivable, Net	2,335	1,522
Inventories	584	629
Assets from Price Risk Management Activities	—	65
Income Taxes Receivable	—	23
Other	456	294
Total	<u>8,584</u>	<u>5,862</u>
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	67,644	64,793
Other Property, Plant and Equipment	4,753	4,479
Total Property, Plant and Equipment	<u>72,397</u>	<u>69,272</u>
Less: Accumulated Depreciation, Depletion and Amortization	<u>(43,971)</u>	<u>(40,673)</u>
Total Property, Plant and Equipment, Net	28,426	28,599
Deferred Income Taxes	11	2
Other Assets	1,215	1,342
Total Assets	<u>\$ 38,236</u>	<u>\$ 35,805</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	\$ 2,242	\$ 1,681
Accrued Taxes Payable	518	206
Dividends Payable	436	217
Liabilities from Price Risk Management Activities	269	—
Current Portion of Long-Term Debt	37	781
Current Portion of Operating Lease Liabilities	240	295
Other	300	280
Total	<u>4,042</u>	<u>3,460</u>
Long-Term Debt	5,072	5,035
Other Liabilities	2,193	2,149
Deferred Income Taxes	4,749	4,859
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, \$0.01 Par, 1,280,000,000 Shares Authorized and 585,521,512 Shares and 583,694,850 Shares Issued at December 31, 2021 and 2020, respectively	206	206
Additional Paid in Capital	6,087	5,945
Accumulated Other Comprehensive Loss	(12)	(12)
Retained Earnings	15,919	14,170
Common Stock Held in Treasury, 257,268 Shares and 124,265 Shares at December 31, 2021 and 2020, respectively	<u>(20)</u>	<u>(7)</u>
Total Stockholders' Equity	<u>22,180</u>	<u>20,302</u>
Total Liabilities and Stockholders' Equity	<u>\$ 38,236</u>	<u>\$ 35,805</u>

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Millions, Except Per Share Data)

	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Stockholders' Equity
Balance at December 31, 2018	\$ 206	\$ 5,659	\$ (2)	\$ 13,543	\$ (42)	\$ 19,364
Net Income	—	—	—	2,735	—	2,735
Common Stock Issued Under Stock Plans	—	—	—	—	—	—
Common Stock Dividends Declared, \$1.0825 Per Share	—	—	—	(629)	—	(629)
Other Comprehensive Income	—	—	(3)	—	—	(3)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(11)	—	—	3	(8)
Restricted Stock and Restricted Stock Units, Net	—	(5)	—	—	5	—
Stock-Based Compensation Expenses	—	175	—	—	—	175
Treasury Stock Issued as Compensation	—	(1)	—	—	7	6
Balance at December 31, 2019	206	5,817	(5)	15,649	(27)	21,640
Net Loss	—	—	—	(605)	—	(605)
Common Stock Issued Under Stock Plans	—	—	—	—	—	—
Common Stock Dividends Declared, \$1.50 Per Share	—	—	—	(874)	—	(874)
Other Comprehensive Loss	—	—	(7)	—	—	(7)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(9)	—	—	9	—
Restricted Stock and Restricted Stock Units, Net	—	(9)	—	—	9	—
Stock-Based Compensation Expenses	—	146	—	—	—	146
Treasury Stock Issued as Compensation	—	—	—	—	2	2
Balance at December 31, 2020	206	5,945	(12)	14,170	(7)	20,302
Net Income	—	—	—	4,664	—	4,664
Common Stock Issued Under Stock Plans	—	17	—	—	—	17
Common Stock Dividends Declared, \$4.9875 Per Share	—	—	—	(2,915)	—	(2,915)
Other Comprehensive Loss	—	—	—	—	—	—
Change in Treasury Stock - Stock Compensation Plans, Net	—	(22)	—	—	(18)	(40)
Restricted Stock and Restricted Stock Units, Net	—	(5)	—	—	5	—
Stock-Based Compensation Expenses	—	152	—	—	—	152
Treasury Stock Issued as Compensation	—	—	—	—	—	—
Balance at December 31, 2021	\$ 206	\$ 6,087	\$ (12)	\$ 15,919	\$ (20)	\$ 22,180

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)

Year Ended December 31	2021	2020	2019
Cash Flows from Operating Activities			
Reconciliation of Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net Income (Loss)	\$ 4,664	\$ (605)	\$ 2,735
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	3,651	3,400	3,750
Impairments	376	2,100	518
Stock-Based Compensation Expenses	152	146	175
Deferred Income Taxes	(122)	(186)	632
(Gains) Losses on Asset Dispositions, Net	(17)	47	(124)
Other, Net	13	12	4
Dry Hole Costs	71	13	28
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	1,152	(1,145)	(180)
Net Cash Received from (Payments for) Settlements of Commodity Derivative Contracts	(638)	1,071	231
Other, Net	7	1	1
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(821)	467	(92)
Inventories	(13)	123	90
Accounts Payable	456	(795)	169
Accrued Taxes Payable	312	(49)	40
Other Assets	(136)	325	358
Other Liabilities	(116)	8	(57)
Changes in Components of Working Capital Associated with Investing Activities	(200)	75	(115)
Net Cash Provided by Operating Activities	8,791	5,008	8,163
Investing Cash Flows			
Additions to Oil and Gas Properties	(3,638)	(3,244)	(6,152)
Additions to Other Property, Plant and Equipment	(212)	(221)	(270)
Proceeds from Sales of Assets	231	192	140
Other Investing Activities	—	—	(10)
Changes in Components of Working Capital Associated with Investing Activities	200	(75)	115
Net Cash Used in Investing Activities	(3,419)	(3,348)	(6,177)
Financing Cash Flows			
Long-Term Debt Borrowings	—	1,484	—
Long-Term Debt Repayments	(750)	(1,000)	(900)
Dividends Paid	(2,684)	(821)	(588)
Treasury Stock Purchased	(41)	(16)	(25)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	19	16	18
Debt Issuance Costs	—	(3)	(5)
Repayment of Finance Lease Liabilities	(37)	(19)	(13)
Net Cash Used in Financing Activities	(3,493)	(359)	(1,513)
Effect of Exchange Rate Changes on Cash	1	—	(1)
Increase in Cash and Cash Equivalents	1,880	1,301	472
Cash and Cash Equivalents at Beginning of Year	3,329	2,028	1,556
Cash and Cash Equivalents at End of Year	\$ 5,209	\$ 3,329	\$ 2,028

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Business. EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively, EOG), explores for, develops, produces and markets crude oil, natural gas liquids (NGLs) and natural gas primarily in major producing basins in the United States of America (United States or U.S.), The Republic of Trinidad and Tobago (Trinidad). EOG is making preparations to drill offshore Australia, as well as evaluating additional exploration, development and exploitation opportunities in these and other select international areas. In addition, EOG is in the process of exiting Block 36 and Block 49 in the Sultanate of Oman (Oman) and is executing an abandonment and reclamation program in Canada. EOG sold its operations in the China Sichuan Basin (China) in the second quarter of 2021.

Principles of Consolidation. The consolidated financial statements of EOG include the accounts of all domestic and foreign subsidiaries. Investments in unconsolidated affiliates, in which EOG is able to exercise significant influence, are accounted for using the equity method. All intercompany accounts and transactions have been eliminated.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt. The carrying values of cash and cash equivalents, commodity derivative contracts, accounts receivable and accounts payable approximate fair value (see Notes 2 and 12).

Effective January 1, 2020, EOG adopted the provisions of Accounting Standards Update (ASU) 2016-13, "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13). ASU 2016-13 changes the impairment model for financial assets and certain other instruments by requiring entities to adopt a forward-looking expected loss model that will result in earlier recognition of credit losses. EOG elected to adopt ASU 2016-13 using the modified retrospective approach with a cumulative effect adjustment to retained earnings as of the effective date. Financial results reported in periods prior to January 1, 2020, are unchanged. EOG assessed its applicable financial assets, which are primarily its accounts receivable from hydrocarbon sales and joint interest billings to partners in oil and gas operations, including foreign state-owned entities in the oil and gas industry. Based on its assessment and various potential remedies ensuring collection, EOG did not record an impact to retained earnings upon adoption and expects current and future credit losses to be immaterial. EOG continues to monitor the credit risk from third-party companies to determine if expected credit losses may become material.

Cash and Cash Equivalents. EOG records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Oil and Gas Operations. EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered commercial quantities of proved reserves. If commercial quantities of proved reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether commercial quantities of proved reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the estimated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made (see Note 16). Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the group. If the expected undiscounted future cash flows, based on EOG's estimate of (and assumptions regarding) future crude oil, NGLs and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

Other Property, Plant and Equipment. Other property, plant and equipment consists of gathering and processing assets, compressors, buildings and leasehold improvements, computer hardware and software, vehicles, and furniture and fixtures. Other property, plant and equipment is generally depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from 3 years to 45 years.

Inventories. Inventories consist primarily of tubular goods, materials for completion operations, well equipment and gathering lines held for use in the exploration for, and development and production of, crude oil, NGLs and natural gas reserves. EOG accounts for inventories at the lower of cost and net realizable value with adjustments made, as appropriate, to recognize any reductions in value.

Revenue Recognition. EOG presents disaggregated revenues by type of commodity within its Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and by geographic areas defined as operating segments. See Note 11.

Revenues are recognized for the sale of crude oil and condensate, NGLs and natural gas at the point control of the product is transferred to the customer, typically when production is delivered and title or risk of loss transfers to the customer. Arrangements for such sales are evidenced by signed contracts with prices typically based on stated market indices, with certain adjustments for product quality and geographic location. As EOG typically invoices customers shortly after performance obligations have been fulfilled, contract assets and contract liabilities are not recognized. The balances of accounts receivable from contracts with customers as of December 31, 2021 and 2020, were \$2,130 million and \$1,337 million, respectively, and were included in Accounts Receivable, Net on the Consolidated Balance Sheets. Losses incurred on receivables from contracts with customers are infrequent and have been immaterial. Certain arrangements provide for the sale of fixed quantities of commodities in future years with pricing mechanisms based on future market prices at time of delivery. EOG does not disclose the value of these obligations given the uncertainty of the future realized transaction price.

Crude Oil and Condensate. EOG sells its crude oil and condensate production at the wellhead or further downstream at a contractually-specified delivery point. Revenue is recognized when control transfers to the customer based on contract terms which reflect prevailing market prices. Any costs incurred prior to the transfer of control, such as gathering and transportation, are recognized as Operating Expenses.

Natural Gas Liquids. EOG delivers certain of its natural gas production to either EOG-owned processing facilities or third-party processing facilities, where extraction of NGLs occurs. For EOG-owned facilities, revenue is recognized after processing upon transfer of NGLs to a customer. For third-party facilities, extracted NGLs are sold to the owner of the processing facility at the tailgate, or EOG takes possession and sells the extracted NGLs at the tailgate or exercises its option to sell further downstream to various customers. Under typical arrangements for third-party facilities, revenue is recognized after processing upon the transfer of control of the NGLs, either at the tailgate of the processing plant or further downstream. EOG recognizes revenues based on contract terms which reflect prevailing market prices, with any costs prior to the transfer of control, such as processing, transportation and fractionation fees, recognized as Transportation Costs and Gathering and Processing Costs, as appropriate.

Natural Gas. EOG sells its natural gas production either at the wellhead or further downstream at a contractually-specified delivery point. In connection with the extraction of NGLs, EOG sells residue gas under separate agreements. Typically, EOG takes possession of the natural gas at the tailgate of the processing facility and sells it at the tailgate or further downstream. In each case, EOG recognizes revenues when control transfers to the customer, based on contract terms which reflect prevailing market prices.

Gathering, Processing and Marketing. Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as fees associated with gathering and processing third-party natural gas and revenues from sales of EOG-owned sand. EOG evaluates whether it is the principal or agent under these transactions. As control of the underlying commodity is transferred to EOG prior to the gathering, processing and marketing activities, EOG considers itself the principal of these arrangements. Accordingly, EOG recognizes these transactions on a gross basis. Purchases of third-party commodities are recorded as Marketing Costs, with sales of third-party commodities and fees received for gathering and processing recorded as Gathering, Processing and Marketing revenues.

Capitalized Interest Costs. Interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. The amount capitalized is an allocation of the interest cost incurred during the reporting period. Capitalized interest is computed only during the exploration and development phases and ceases once production begins. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings.

Accounting for Risk Management Activities. Derivative instruments are recorded on the balance sheet as either an asset or liability measured at fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ended December 31, 2021, EOG elected not to designate any of its financial commodity derivative instruments as accounting hedges and, accordingly, changes in the fair value of these outstanding derivative instruments are recognized as gains or losses in the period of change. The gains or losses are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). The related cash flow impact of settled contracts is reflected as cash flows from operating activities. EOG employs net presentation of derivative assets and liabilities for financial reporting purposes when such assets and liabilities are with the same counterparty and subject to a master netting arrangement. See Note 12.

Income Taxes. Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate. See Note 6.

Effective January 1, 2021, EOG adopted the provisions of Accounting Standards Update (ASU), "Income Taxes (Topic 740) Simplifying the Accounting for Income Taxes" (ASU 2019-12). ASU 2019-12 amends certain aspects of accounting for income taxes, including the removal of specific exceptions within existing U.S. GAAP related to the incremental approach for intraperiod tax allocation and updates to the general methodology for calculating income taxes in interim periods, among other changes. ASU 2019-12 also requires an entity to reflect the effect of an enacted change in tax laws or rates in the annual effective tax rate computation in the interim period that includes the enactment date, among other requirements. The effects of ASU 2019-12 applicable to EOG were all required on a prospective basis. There was no impact upon adoption of ASU 2019-12 to EOG's consolidated financial statements or related disclosures.

Foreign Currency Translation. The United States dollar is the functional currency for all of EOG's consolidated subsidiaries except for its Canadian subsidiaries, for which the functional currency is the Canadian dollar. For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. See Note 4.

Net Income (Loss) Per Share. Basic net income (loss) per share is computed on the basis of the weighted-average number of common shares outstanding during the period. Diluted net income (loss) per share is computed based upon the weighted-average number of common shares outstanding during the period plus the assumed issuance of common shares for all potentially dilutive securities. See Note 9.

Stock-Based Compensation. EOG measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. See Note 7.

Leases. Effective January 1, 2019, EOG adopted the provisions of ASU 2016-02, "Leases (Topic 842)" (ASU 2016-02). ASU 2016-02 and other related ASUs require that lessees recognize a right-of-use (ROU) asset and related lease liability, representing the obligation to make lease payments for certain lease transactions, on the Consolidated Balance Sheets and disclose additional leasing information.

EOG elected to adopt ASU 2016-02 and other related ASUs using the modified retrospective approach with a cumulative-effect adjustment to the opening balance of retained earnings as of the effective date. Financial results reported in periods prior to January 1, 2019, are unchanged. Additionally, EOG elected the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases, or (iii) initial direct costs for any existing leases, but did not elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date. EOG also elected the practical expedient under ASU 2018-01, "Leases (Topic 842) - Land Easement Practical Expedient for Transition to Topic 842," and did not evaluate existing or expired land easements not previously accounted for as leases prior to the January 1, 2019 effective date. There was no impact to retained earnings upon adoption of ASU 2016-02 and other related ASUs.

In the ordinary course of business, EOG enters into contracts for drilling, fracturing, compression, real estate and other services which contain equipment and other assets and that meet the definition of a lease under ASU 2016-02. The lease term for these contracts, which includes any renewals at EOG's option that are reasonably certain to be exercised, ranges from one month to 30 years.

ROU assets and related liabilities are recognized on the commencement date on the Consolidated Balance Sheets based on future lease payments, discounted based on the rate implicit in the contract, if readily determinable, or EOG's incremental borrowing rate commensurate with the lease term of the contract. EOG estimates its incremental borrowing rate based on the approximate rate required to borrow on a collateralized basis. Contracts with lease terms of less than 12 months are not recorded on the Consolidated Balance Sheets, but instead are disclosed as short-term lease cost. EOG has elected not to separate non-lease components from all leases, excluding those for fracturing services, real estate and salt water disposal, as lease payments under these contracts contain significant non-lease components, such as labor and operating costs. See Note 18.

Recently Issued Accounting Standards. In March 2020, the FASB issued ASU 2020-04, "Reference Rate Reform (Topic 848)" (ASU 2020-04), which provides optional expedients and exceptions for accounting treatment of contracts which are affected by the anticipated discontinuation of the London InterBank Offered Rate (LIBOR) and other rates resulting from rate reform. Contract terms that are modified due to the replacement of a reference rate are not required to be remeasured or reassessed under relevant accounting standards. Early adoption is permitted. ASU 2020-04 covers certain contracts which reference these rates and that are entered into on or before December 31, 2022. EOG has evaluated the provisions of ASU 2020-04 and does not expect the application of ASU 2020-04 to have a material impact on its consolidated financial statements and related disclosures related to its \$2.0 billion senior unsecured Revolving Credit Agreement.

2. Long-Term Debt

Long-Term Debt at December 31, 2021 and 2020 consisted of the following (in millions):

	<u>2021</u>	<u>2020</u>
4.100% Senior Notes due 2021	\$ —	\$ 750
2.625% Senior Notes due 2023	1,250	1,250
3.15% Senior Notes due 2025	500	500
4.15% Senior Notes due 2026	750	750
6.65% Senior Notes due 2028	140	140
4.375% Senior Notes due 2030	750	750
3.90% Senior Notes due 2035	500	500
5.10% Senior Notes due 2036	250	250
4.950% Senior Notes due 2050	750	750
Long-Term Debt	<u>4,890</u>	<u>5,640</u>
Finance Leases (see Note 18)	250	212
Less: Current Portion of Long-Term Debt	37	781
Unamortized Debt Discount	27	31
Debt Issuance Costs	4	5
Total Long-Term Debt	<u><u>\$ 5,072</u></u>	<u><u>\$ 5,035</u></u>

The senior notes in the table above are senior, unsecured obligations that rank equally in right of payment with all of our other unsecured and unsubordinated outstanding debt. At December 31, 2021, the aggregate annual maturities of long-term debt (excluding finance lease obligations) were zero in 2022, \$1.25 billion in 2023, zero in 2024, \$500 million in 2025 and \$750 million in 2026.

At December 31, 2021 and 2020, EOG had no outstanding commercial paper borrowings and did not utilize any commercial paper borrowings during 2021 and 2020.

On February 1, 2021, EOG repaid upon maturity the \$750 million aggregate principal amount of its 4.100% Senior Notes due 2021.

On June 1, 2020, EOG repaid upon maturity the \$500 million aggregate principal amount of its 4.40% Senior Notes due 2020.

On April 14, 2020, EOG closed on its offering of \$750 million aggregate principal amount of its 4.375% Senior Notes due 2030 and \$750 million aggregate principal amount of its 4.950% Senior Notes due 2050 (together, the Notes). Interest on the Notes is payable semi-annually in arrears on April 15 and October 15 of each year, beginning on October 15, 2020. EOG received net proceeds of \$1.48 billion from the issuance of the Notes, which were used to repay the 4.40% Senior Notes due 2020 when they matured on June 1, 2020 (see above), and for general corporate purposes, including the funding of capital expenditures.

On April 1, 2020, EOG repaid upon maturity the \$500 million aggregate principal amount of its 2.45% Senior Notes due 2020.

EOG currently has a \$2.0 billion senior unsecured Revolving Credit Agreement (the Agreement) with domestic and foreign lenders (Banks). The Agreement has a scheduled maturity date of June 27, 2024, and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods subject to certain terms and conditions. The Agreement (i) commits the Banks to provide advances up to an aggregate principal amount of \$2.0 billion at any one time outstanding, with an option for EOG to request increases in the aggregate commitments to an amount not to exceed \$3.0 billion, subject to certain terms and conditions and (ii) includes a swingline subfacility and a letter of credit subfacility. Advances under the Agreement will accrue interest based, at EOG's option, on either the LIBOR plus an applicable margin (Eurodollar rate) or the base rate (as defined in the Agreement) plus an applicable margin. The Agreement contains representations, warranties, covenants and events of default that EOG believes are customary for investment-grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a ratio of total debt-to-capitalization (as such terms are defined in the Agreement) of no greater than 65%. At December 31, 2021, EOG was in compliance with this financial covenant. At December 31, 2021 and December 31, 2020, there were no borrowings or letters of credit outstanding under the Agreement. The Eurodollar rate and base rate (inclusive of the applicable margin), had there been any amounts borrowed under the Agreement at December 31, 2021, would have been 1.00% and 3.25%, respectively.

3. Stockholders' Equity

Common Stock. In September 2001, EOG's Board of Directors (Board) authorized the repurchase of an aggregate maximum of 10 million shares of common stock that superseded all previous authorizations (September 2001 Authorization). EOG last repurchased shares under the September 2001 Authorization in March 2003. As of November 3, 2021, 6,386,200 shares remained available for purchase under September 2001 Authorization. Effective November 4, 2021, the Board (i) established a new share repurchase authorization to allow for the repurchase by EOG of up to \$5 billion of common stock (November 2021 Authorization) and (ii) revoked and terminated the September 2001 Authorization. EOG did not repurchase any shares under the November 2021 Authorization during the period from November 4, 2021 through December 31, 2021 and, accordingly, \$5 billion remained available for purchase under the November 2021 Authorization as of December 31, 2021.

Shares of common stock are from time to time withheld by, or returned to, EOG in satisfaction of tax withholding obligations arising upon the exercise of employee stock options or stock-settled stock appreciation rights (SARs), the vesting of restricted stock, restricted stock unit or performance unit grants or in payment of the exercise price of employee stock options. Such shares withheld or returned prior to November 4, 2021 have not counted against the September 2001 Authorization, and such shares withheld or returned on or subsequent to November 4, 2021 will not count against the November 2021 Authorization. Shares purchased, withheld and returned are held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock-based compensation plans and any other approved transactions or activities for which such shares of common stock may be required.

On February 24, 2022, the Board declared a quarterly cash dividend on the common stock of \$0.75 per share payable April 29, 2022, to stockholders of record as of April 15, 2022. The Board also declared a special dividend of \$1.00 per share payable March 29, 2022, to stockholders of record as of March 15, 2022.

On November 4, 2021, the Board (i) increased the quarterly cash dividend on the common stock from the previous \$0.4125 per share to \$0.75 per share, effective beginning with the dividend paid on January 28, 2022, to stockholders of record as of January 14, 2022 and (ii) declared a special cash dividend on the common stock of \$2.00 per share, paid on December 30, 2021, to stockholders of record as of December 15, 2021.

On May 6, 2021, the Board declared a special cash dividend on the common stock of \$1.00 per share. The special cash dividend was paid on July 30, 2021 to stockholders of record as of July 16, 2021 (and was in addition to the quarterly cash dividend of \$0.4125 per share also paid on July 30, 2021 to stockholders of record as of July 16, 2021).

On February 25, 2021, the Board increased the quarterly cash dividend on the common stock from the previous \$0.375 per share to \$0.4125 per share, effective beginning with the dividend to be paid on April 30, 2021, to stockholders of record as of April 16, 2021.

On February 27, 2020, the Board increased the quarterly cash dividend on the common stock from the previous \$0.2875 per share to \$0.375 per share, effective beginning with the dividend to be paid on April 30, 2020, to stockholders of record as of April 16, 2020.

On May 2, 2019, the Board increased the quarterly cash dividend on the common stock from the previous \$0.22 per share to \$0.2875 per share, effective beginning with the dividend paid on July 31, 2019, to stockholders of record as of July 17, 2019.

The following summarizes Common Stock activity for each of the years ended December 31, 2021, 2020 and 2019 (in thousands):

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2018	580,408	(385)	580,023
Common Stock Issued Under Stock-Based Compensation Plans	1,688	—	1,688
Treasury Stock Purchased ⁽¹⁾	—	(310)	(310)
Common Stock Issued Under Employee Stock Purchase Plan	117	107	224
Treasury Stock Issued Under Stock-Based Compensation Plans	—	289	289
Balance at December 31, 2019	582,213	(299)	581,914
Common Stock Issued Under Stock-Based Compensation Plans	1,482	—	1,482
Treasury Stock Purchased ⁽¹⁾	—	(389)	(389)
Common Stock Issued Under Employee Stock Purchase Plan	—	377	377
Treasury Stock Issued Under Stock-Based Compensation Plans	—	187	187
Balance at December 31, 2020	583,695	(124)	583,571
Common Stock Issued Under Stock-Based Compensation Plans	1,511	—	1,511
Treasury Stock Purchased ⁽¹⁾	—	(504)	(504)
Common Stock Issued Under Employee Stock Purchase Plan	316	—	316
Treasury Stock Issued Under Stock-Based Compensation Plans	—	371	371
Balance at December 31, 2021	585,522	(257)	585,265

(1) Represents shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or SARs or the vesting of restricted stock, restricted stock unit or performance unit grants or (ii) in payment of the exercise price of employee stock options.

Preferred Stock. EOG currently has one authorized series of preferred stock. As of December 31, 2021, there were no shares of preferred stock outstanding.

4. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes certain transactions that have generally been reported in the Consolidated Statements of Stockholders' Equity. The components of Accumulated Other Comprehensive Loss at December 31, 2021 and 2020 consisted of the following (in millions):

	Foreign Currency Translation Adjustment	Other	Total
December 31, 2019	\$ (3)	\$ (2)	\$ (5)
Other comprehensive loss before taxes	(7)	—	(7)
Tax effects	—	—	—
Other comprehensive loss	(7)	—	(7)
December 31, 2020	(10)	(2)	(12)
Other comprehensive loss before taxes	(1)	1	—
Tax effects	—	—	—
Other comprehensive loss	(1)	1	—
December 31, 2021	\$ (11)	\$ (1)	\$ (12)

No significant amount was reclassified out of Accumulated Other Comprehensive Loss during the years ended December 31, 2021, 2020 and 2019.

5. Other Income, Net

Other income, net for 2021 included equity income from investments in ammonia plants in Trinidad (\$18 million) and interest income (\$3 million), partially offset by an upward adjustment to deferred compensation expense (\$13 million). Other income, net for 2020 included interest income (\$12 million), partially offset by equity losses from investments in ammonia plants in Trinidad (\$2 million). Other income, net for 2019 included interest income (\$26 million) and net foreign currency transaction gains (\$2 million).

6. Income Taxes

The principal components of EOG's total net deferred income tax liabilities at December 31, 2021 and 2020 were as follows (in millions):

	2021	2020
Deferred Income Tax Assets (Liabilities)		
Foreign Oil and Gas Exploration and Development Costs Deducted for Tax Under Book Depreciation, Depletion and Amortization	\$ (19)	\$ 25
Foreign Asset Retirement Obligations	51	—
Foreign Accrued Expenses and Liabilities	15	—
Foreign Net Operating Loss	80	74
Foreign Valuation Allowances	(111)	(97)
Foreign Other	(5)	—
Total Net Deferred Income Tax Assets	\$ 11	\$ 2
Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	\$ 5,063	\$ 5,028
Commodity Hedging Contracts	(97)	15
Deferred Compensation Plans	(57)	(43)
Equity Awards	(86)	(103)
Undistributed Foreign Earnings	—	10
Other	(74)	(48)
Total Net Deferred Income Tax Liabilities	\$ 4,749	\$ 4,859
Total Net Deferred Income Tax Liabilities	\$ 4,738	\$ 4,857

The components of Income (Loss) Before Income Taxes for the years indicated below were as follows (in millions):

	2021	2020	2019
United States	\$ 5,787	\$ (756)	\$ 3,466
Foreign	146	17	79
Total	\$ 5,933	\$ (739)	\$ 3,545

The principal components of EOG's Income Tax Provision (Benefit) for the years indicated below were as follows (in millions):

	2021	2020	2019
Current:			
Federal	\$ 1,203	\$ (108)	\$ (152)
State	85	7	10
Foreign	105	40	81
Total	<u>1,393</u>	<u>(61)</u>	<u>(61)</u>
Deferred:			
Federal	(41)	(153)	627
State	(62)	(15)	33
Foreign	(19)	(18)	(28)
Total	<u>(122)</u>	<u>(186)</u>	<u>632</u>
Other Non-Current: ⁽¹⁾			
Federal	—	113	245
Foreign	(2)	—	(6)
Total	<u>(2)</u>	<u>113</u>	<u>239</u>
Income Tax Provision (Benefit)	<u>\$ 1,269</u>	<u>\$ (134)</u>	<u>\$ 810</u>

(1) Includes changes in certain amounts that are expected to be paid or received beyond the next twelve months. The primary component in 2020 and 2019 is refundable alternative minimum tax (AMT) credits.

The differences between taxes computed at the U.S. federal statutory tax rate and EOG's effective rate for the years indicated below were as follows:

	2021	2020	2019
Statutory Federal Income Tax Rate	<u>21.0 %</u>	<u>21.0 %</u>	<u>21.0 %</u>
State Income Tax, Net of Federal Benefit	0.3	0.9	1.0
Income Tax Provision Related to Foreign Operations	0.9	(0.1)	0.9
Income Tax Provision Related to Canadian Operations	—	(2.4)	—
Stock-Based Compensation	0.2	(2.9)	—
Other	(1.0)	1.7	—
Effective Income Tax Rate	<u>21.4 %</u>	<u>18.2 %</u>	<u>22.9 %</u>

The net effective tax rate of 21% in 2021 was higher than the prior year rate of 18% mostly due to taxes attributable to EOG's foreign operations and stock-based compensation tax deficiencies increasing the effective tax rate on pretax income in 2021 and decreasing the effective tax rate on pretax loss in 2020.

Deferred tax assets are recorded for future deductible amounts and certain other tax benefits, such as tax NOLs and tax credit carryforwards, provided that management assesses the utilization of such assets to be "more likely than not." Management assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to use the existing deferred tax assets. On the basis of this evaluation, EOG has recorded valuation allowances for the portion of certain foreign and state deferred tax assets that management does not believe are more likely than not to be realized.

The principal components of EOG's rollforward of valuation allowances for deferred income tax assets for the years indicated below were as follows (in millions):

	<u>2021</u>	<u>2020</u>	<u>2019</u>
Beginning Balance	\$ 219	\$ 201	\$ 167
Increase ⁽¹⁾	15	25	31
Decrease ⁽²⁾	(14)	(11)	—
Other ⁽³⁾	(1)	4	3
Ending Balance	<u>\$ 219</u>	<u>\$ 219</u>	<u>\$ 201</u>

(1) Increase in valuation allowance related to the generation of tax NOLs and other deferred tax assets.

(2) Decrease in valuation allowance associated with adjustments to certain deferred tax assets and their related allowances.

(3) Represents dispositions, revisions and/or foreign exchange rate variances and the effect of statutory income tax rate changes.

As of December 31, 2021, EOG had state income tax NOLs of approximately \$2 billion. Certain state NOLs have an indefinite carryforward and all others expire between 2022 and 2040. EOG also has Canadian NOLs of \$297 million, some of which can be carried forward up to 20 years. As described previously, these NOLs and other less significant tax benefits have been evaluated for the likelihood of utilization, and valuation allowances have been established for the portion of these deferred income tax assets that do not meet the “more likely than not” threshold.

The total balance of unrecognized tax benefits for all jurisdictions at December 31, 2021, was \$9 million, resulting from the tax treatment of certain compensation deductions, of which the full amount may potentially have an earnings impact. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. No interest expense has been recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) related to the unrecognized tax benefits as these positions are immaterial or will be claimed either on amended returns or as self-proposed audit adjustments, which if sustained, will result in refunds. EOG anticipates that the amount of the unrecognized tax benefits may change due to favorable audit developments expected to occur during the next twelve months. EOG and its subsidiaries file income tax returns and are subject to tax audits in the U.S. and various state, local and foreign jurisdictions. EOG's earliest open tax years in its principal jurisdictions are as follows: U.S. federal (2019), Canada (2017), Trinidad (2014) and Oman (2020).

EOG's foreign subsidiaries' undistributed earnings are not considered to be permanently reinvested outside of the U.S. and deferred income taxes have been accrued on any such outside basis differences. Additionally, EOG's foreign earnings may be subject to the U.S. federal "global intangible low-taxed income" (GILTI) inclusion. EOG records any GILTI tax as a period expense.

7. Employee Benefit Plans

Stock-Based Compensation

During 2021, EOG maintained various stock-based compensation plans as discussed below. EOG recognizes compensation expense on grants of stock options, SARs, restricted stock and restricted stock units, performance units and grants made under the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP). Stock-based compensation expense is calculated based upon the grant date estimated fair value of the awards, net of forfeitures, based upon EOG's historical employee turnover rate. Compensation expense is amortized over the shorter of the vesting period or the period from date of grant until the date the employee becomes eligible to retire without company approval.

Stock-based compensation expense is included on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) based upon the job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years ended December 31, 2021, 2020 and 2019 was as follows (in millions):

	2021	2020	2019
Lease and Well	\$ 49	\$ 52	\$ 56
Gathering and Processing Costs	3	1	1
Exploration Costs	20	21	26
General and Administrative	80	72	92
Total	<u>\$ 152</u>	<u>\$ 146</u>	<u>\$ 175</u>

The Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) provided for grants of stock options, SARs, restricted stock and restricted stock units, performance units, and other stock-based awards.

EOG's stockholders approved the EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (2021 Plan) at the 2021 Annual Meeting of Stockholders. Therefore, no further grants were made from the 2008 Plan from and after the April 29, 2021 effective date of the 2021 Plan. The 2021 Plan provides for grants of stock options, SARs, restricted stock and restricted stock units, restricted stock units with performance-based conditions (together with the performance units granted under the 2008 Plan, "Performance Units") and other stock-based awards, up to an aggregate maximum of 20 million shares of common stock, plus any shares that are subject to outstanding awards under the 2008 Plan as of April 29, 2021, that are subsequently canceled, forfeited, expire or are otherwise not issued or are settled in cash. Under the 2021 Plan, grants may be made to employees and non-employee members of EOG's Board of Directors (Board).

The vesting schedules for grants of stock options, SARs, restricted stock and restricted stock units, and Performance Units are generally as follows:

Grant Type	Vesting Schedule
Stock Options/SARs	Vesting in increments of one-third on each of the first three anniversaries, respectively, of the date of grant
Restricted Stock/Restricted Stock Units	"Cliff" vesting three years from the date of grant
Performance Units	"Cliff" vesting on the February 28th following the three-year performance period and the Compensation and Human Resources Committee's certification of the applicable performance multiple

At December 31, 2021, approximately 18 million common shares remained available for grant under the 2021 Plan. EOG's policy is to issue shares related to the 2021 Plan from previously authorized unissued shares or treasury shares to the extent treasury shares are available.

During 2021, 2020 and 2019, EOG issued shares in connection with stock option/SAR exercises, restricted stock grants, restricted stock unit and Performance Unit releases and ESPP purchases. Net tax deficiencies recognized within the income tax provision were \$(11) million, \$(22) million and \$(1) million for the years ended December 31, 2021, 2020 and 2019, respectively.

Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan. Participants in EOG's stock-based compensation plans (including the 2008 Plan and 2021 Plan) have been or may be granted options to purchase shares of Common Stock. In addition, participants in EOG's stock plans (including the 2008 Plan and 2021 Plan) have been or may be granted SARs, representing the right to receive shares of Common Stock based on the appreciation in the stock price from the date of grant on the number of SARs granted. Stock options and SARs are granted at a price not less than the market price of the Common Stock on the date of grant. Terms for stock options and SARs granted have generally not exceeded a maximum term of seven years. EOG's ESPP allows eligible employees to semi-annually purchase, through payroll deductions, shares of Common Stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employee's pay (subject to certain ESPP limits) during each of the two six-month offering periods each year.

The fair value of stock option grants and SAR grants is estimated using the Hull-White II binomial option pricing model. The fair value of ESPP grants is estimated using the Black-Scholes-Merton model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled \$48 million, \$62 million and \$63 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2021, 2020 and 2019 were as follows:

	Stock Options/SARs			ESPP		
	2021	2020	2019	2021	2020	2019
Weighted Average Fair Value of Grants	\$ 24.92	\$ 11.06	\$ 19.49	\$ 18.12	\$ 19.14	\$ 22.83
Expected Volatility	42.24 %	44.47 %	32.02 %	51.27 %	53.48 %	34.78 %
Risk-Free Interest Rate	0.50 %	0.21 %	1.69 %	0.07 %	0.90 %	2.27 %
Dividend Yield	2.26 %	3.27 %	1.39 %	2.89 %	2.27 %	1.04 %
Expected Life	5.2 years	5.2 years	5.1 years	0.5 years	0.5 years	0.5 years

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's Common Stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock option, SAR and ESPP grants.

The following table sets forth the stock option and SAR transactions for the years ended December 31, 2021, 2020 and 2019 (stock options and SARs in thousands):

	2021		2020		2019	
	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price
Outstanding at January 1	10,186	\$ 84.08	9,395	\$ 94.53	8,310	\$ 96.90
Granted	1,982	81.68	1,996	37.63	1,965	75.39
Exercised ⁽¹⁾	(1,130)	63.98	(23)	69.59	(606)	61.43
Forfeited	(1,069)	98.15	(1,182)	88.93	(274)	102.57
Outstanding at December 31	9,969	84.37	10,186	84.08	9,395	94.53
Stock Options/SARs Exercisable at December 31	6,197	95.33	6,343	96.41	5,275	94.21

(1) The total intrinsic value of stock options/SARs exercised during the years 2021, 2020 and 2019 was \$27 million, \$0.4 million and \$14 million, respectively. The intrinsic value is based upon the difference between the market price of the Common Stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2021, there were 9.7 million stock options/SARs vested or expected to vest with a weighted average grant price of \$84.97 per share, an intrinsic value of \$120 million and a weighted average remaining contractual life of 4.1 years.

The following table summarizes certain information for the stock options and SARs outstanding and exercisable at December 31, 2021 (stock options and SARs in thousands):

Stock Options/SARs Outstanding					Stock Options/SARs Exercisable			
Range of Grant Prices	Stock Options/SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value ⁽¹⁾	Stock Options/SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value ⁽¹⁾
\$ 34.00 to \$ 52.99	1,640	6	\$ 37.50		414	5	\$ 37.46	
53.00 to 75.99	1,906	4	73.68		1,313	3	73.11	
76.00 to 90.99	1,976	7	81.86		33	2	83.71	
91.00 to 95.99	1,114	2	94.95		1,109	2	94.96	
96.00 to 101.99	1,657	3	96.34		1,652	3	96.33	
102.00 to 129.99	1,676	4	126.51		1,676	4	126.51	
	<u>9,969</u>	4	84.37	\$ 127	<u>6,197</u>	3	95.33	\$ 42

(1) Based upon the difference between the closing market price of the Common Stock on the last trading day of the year and the grant price of in-the-money stock options and SARs, in millions.

At December 31, 2021, unrecognized compensation expense related to non-vested stock option and SAR grants totaled \$60 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.1 years.

At the 2018 Annual Meeting of Stockholders, EOG stockholders approved an amendment and restatement of the ESPP to (among other changes) increase the number of shares available for grant. At December 31, 2021, approximately 1.6 million shares of Common Stock remained available for grant under the ESPP. The following table summarizes ESPP activity for the years ended December 31, 2021, 2020 and 2019 (in thousands, except number of participants):

	2021	2020	2019
Approximate Number of Participants	2,036	2,063	1,998
Shares Purchased	316	377	224
Aggregate Purchase Price	\$ 17,224	\$ 16,103	\$ 16,533

Restricted Stock and Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. Upon vesting of restricted stock, shares of Common Stock are released to the employee. Upon vesting, restricted stock units are converted into shares of Common Stock and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled \$89 million, \$75 million and \$97 million for the years ended December 31, 2021, 2020 and 2019, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2021, 2020 and 2019 (shares and units in thousands):

	2021		2020		2019	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	4,742	\$ 74.97	4,546	\$ 90.16	3,792	\$ 96.64
Granted	1,422	81.50	1,488	38.10	1,749	80.01
Released ⁽¹⁾	(1,388)	101.00	(1,213)	85.92	(855)	96.93
Forfeited	(96)	68.26	(79)	86.52	(140)	97.54
Outstanding at December 31 ⁽²⁾	<u>4,680</u>	<u>69.37</u>	<u>4,742</u>	<u>74.97</u>	<u>4,546</u>	<u>90.16</u>

- (1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2021, 2020 and 2019 was \$110 million, \$48 million and \$70 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.
- (2) The total intrinsic value of restricted stock and restricted stock units outstanding at December 31, 2021, 2020 and 2019 was \$416 million, \$236 million and \$381 million, respectively. The intrinsic value is based on the closing market price of the Common Stock on the last trading day of the year.

At December 31, 2021, unrecognized compensation expense related to restricted stock and restricted stock units totaled \$199 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 1.5 years.

Performance Units. EOG has granted Performance Units to its executive officers annually since 2012. As more fully discussed in the grant agreements, the performance metric applicable to these performance-based grants is EOG's total shareholder return over a three-year performance period relative to the total shareholder return of a designated group of peer companies (Performance Period). Upon the application of the performance multiple at the completion of the Performance Period, a minimum of 0% and a maximum of 200% of the Performance Units granted could be outstanding. The fair value of the Performance Units is estimated using a Monte Carlo simulation. Stock-based compensation expense related to the Performance Unit grants totaled \$15 million, \$9 million and \$15 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Weighted average fair values and valuation assumptions used to value Performance Units during the years ended December 31, 2021, 2020 and 2019 were as follows:

	2021	2020	2019
Weighted Average Fair Value of Grants	\$ 95.16	\$ 42.77	\$ 79.98
Expected Volatility	53.80 %	47.27 %	29.20 %
Risk-Free Interest Rate	0.59 %	0.16 %	1.51 %

Expected volatility is based on the term-matched historical volatility over the simulated term, which is calculated as the time between the grant date and the end of the Performance Period. The risk-free interest rate is derived from the Treasury Constant Maturities yield curve on the grant date.

The following table sets forth the Performance Unit transactions for the years ended December 31, 2021, 2020 and 2019 (units in thousands):

	2021		2020		2019	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	613	\$ 88.38	598	\$ 103.91	539	\$ 116.96
Granted	222	95.16	172	42.77	172	79.98
Granted for Performance Multiple ⁽¹⁾	19	113.81	66	119.10	72	80.64
Released ⁽²⁾	(175)	113.06	(223)	103.87	(185)	110.65
Forfeited	—	—	—	—	—	—
Outstanding at December 31 ⁽³⁾	<u>679</u> ⁽⁴⁾	84.97	<u>613</u>	88.38	<u>598</u>	103.91

- (1) Upon completion of the Performance Period for the Performance Units granted in 2017, 2016 and 2015, a performance multiple of 125%, 150% and 200%, respectively, was applied to each of the grants resulting in additional grants of Performance Units in February 2021, 2020 and 2019.
- (2) The total intrinsic value of Performance Units released during the years ended December 31, 2021, 2020 and 2019 was \$13 million, \$13 million and \$15 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date Performance Units are released.
- (3) The total intrinsic value of Performance Units outstanding at December 31, 2021, 2020 and 2019 was \$60 million, \$31 million and \$50 million, respectively. The intrinsic value is based on the closing market price of the Common Stock on the last trading day of the year.
- (4) Upon the application of the relevant performance multiple at the completion of each of the remaining Performance Periods, a minimum of zero and a maximum of 1,358 Performance Units could be outstanding.

At December 31, 2021, unrecognized compensation expense related to Performance Units totaled \$13 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 1.9 years.

Upon completion of the Performance Period for the Performance Units granted in September 2018, a performance multiple of 50% was applied to the grants resulting in a forfeiture of 56,671 Performance Units in February 2022.

Pension Plans. EOG has a defined contribution pension plan in place for most of its employees in the United States. EOG's contributions to the pension plan are based on various percentages of compensation and, in some instances, are based upon the amount of the employees' contributions. EOG's total costs recognized for the plan were \$52 million, \$46 million and \$51 million for 2021, 2020 and 2019, respectively.

In addition, EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. These pension plans are available to most employees of the Trinidadian subsidiary. EOG's combined contributions to these plans were \$1 million, for each of 2021, 2020 and 2019, respectively.

For the Trinidadian defined benefit pension plan, the benefit obligation, fair value of plan assets and (prepaid)/accrued benefit cost totaled \$13 million, \$14 million and \$(0.1) million, respectively, at December 31, 2021, and \$13 million, \$12 million and \$0.1 million, respectively, at December 31, 2020.

Postretirement Health Care. EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents, the costs of which are not material.

8. Commitments and Contingencies

Letters of Credit and Guarantees. At December 31, 2021 and 2020, respectively, EOG had standby letters of credit and guarantees outstanding totaling approximately \$831 million and \$854 million, primarily representing guarantees of payment or performance obligations on behalf of subsidiaries. As of February 17, 2022, EOG had received no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2021, total minimum commitments from purchase and service obligations and transportation and storage service commitments not qualifying as leases, based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars into United States dollars at December 31, 2021, were as follows (in millions):

	Total Minimum Commitments
2022	\$ 1,335
2023	1,045
2024	823
2025	673
2026	579
2027 and beyond	2,133
	\$ 6,588

Contingencies. There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

9. Net Income (Loss) Per Share

The following table sets forth the computation of Net Income (Loss) Per Share for the years ended December 31, 2021, 2020 and 2019 (in millions, except per share data):

	2021	2020	2019
Numerator for Basic and Diluted Earnings per Share -			
Net Income (Loss)	\$ 4,664	\$ (605)	\$ 2,735
Denominator for Basic Earnings per Share -			
Weighted Average Shares	581	579	578
Potential Dilutive Common Shares -			
Stock Options/SARs	—	—	—
Restricted Stock/Units and Performance Units	3	—	3
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	584	579	581
Net Income (Loss) Per Share			
Basic	\$ 8.03	\$ (1.04)	\$ 4.73
Diluted	\$ 7.99	\$ (1.04)	\$ 4.71

The diluted earnings per share calculation excludes stock option, SAR, restricted stock, restricted stock unit, Performance Unit and ESPP grants that were anti-dilutive. Shares underlying the excluded stock option, SAR and ESPP grants were 6 million, 10 million and 6 million for the years ended December 31, 2021, 2020 and 2019, respectively. For the year ended December 31, 2020, 5 million shares underlying grants of restricted stock, restricted stock units and Performance Units were excluded.

10. Supplemental Cash Flow Information

Net cash paid for (received from) interest and income taxes was as follows for the years ended December 31, 2021, 2020 and 2019 (in millions):

	<u>2021</u>	<u>2020</u>	<u>2019</u>
Interest, Net of Capitalized Interest	\$ 185	\$ 205	\$ 187
Income Taxes, Net of Refunds Received	\$ 1,114	\$ (206)	\$ (292)

EOG's accrued capital expenditures at December 31, 2021, 2020 and 2019 were \$592 million, \$414 million and \$612 million, respectively.

Non-cash investing activities for the year ended December 31, 2021, included additions of \$50 million to EOG's oil and gas properties as a result of property exchanges and an addition of \$74 million to EOG's other property, plant and equipment made in connection with finance lease transactions for storage facilities.

Non-cash investing activities for the year ended December 31, 2020, included additions of \$212 million to EOG's oil and gas properties as a result of property exchanges and an addition of \$174 million to EOG's other property, plant and equipment made in connection with finance lease transactions for storage facilities.

Non-cash investing activities for the year ended December 31, 2019, included additions of \$150 million to EOG's oil and gas properties as a result of property exchanges.

Cash paid for leases for the years ended December 31, 2021, 2020 and 2019, is disclosed in Note 18.

11. Business Segment Information

EOG's operations are all crude oil, NGLs and natural gas exploration and production-related. The Segment Reporting Topic of the ASC establishes standards for reporting information about operating segments in annual financial statements. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker, or decision-making group, in deciding how to allocate resources and in assessing performance. EOG's chief operating decision-making process is informal and involves the Chief Executive Officer and other key officers. This group routinely reviews and makes operating decisions related to significant issues associated with each of EOG's major producing areas (including in the United States and in Trinidad) and its exploration programs both inside and outside the United States. For segment reporting purposes, the chief operating decision makers consider the major United States producing areas to be one operating segment.

Financial information by reportable segment is presented below as of and for the years ended December 31, 2021, 2020 and 2019 (in millions):

	United States	Trinidad	Other International ⁽¹⁾	Total
2021				
Crude Oil and Condensate	\$ 11,094	\$ 31	\$ —	\$ 11,125
Natural Gas Liquids	1,812	—	—	1,812
Natural Gas	2,156	270	18	2,444
Losses on Mark-to-Market Commodity Derivative Contracts	(1,152)	—	—	(1,152)
Gathering, Processing and Marketing	4,287	1	—	4,288
Gains (Losses) on Asset Dispositions, Net	(40)	(2)	59	17
Other, Net	108	—	—	108
Operating Revenues and Other ⁽²⁾	18,265	300	77	18,642
Depreciation, Depletion and Amortization	3,558	87	6	3,651
Operating Income (Loss) ⁽³⁾	6,013	151	(62)	6,102
Interest Income	3	—	—	3
Other Income (Expense)	(14)	8	12	6
Net Interest Expense	178	—	—	178
Income (Loss) Before Income Taxes	5,824	159	(50)	5,933
Income Tax Provision (Benefit)	1,247	66	(44)	1,269
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	3,557	55	5	3,617
Total Property, Plant and Equipment, Net	28,213	204	9	28,426
Total Assets	37,436	637	163	38,236
2020				
Crude Oil and Condensate	\$ 5,774	\$ 11	\$ 1	\$ 5,786
Natural Gas Liquids	668	—	—	668
Natural Gas	614	169	54	837
Gains on Mark-to-Market Commodity Derivative Contracts	1,145	—	—	1,145
Gathering, Processing and Marketing	2,581	2	—	2,583
Losses on Asset Dispositions, Net	(47)	—	—	(47)
Other, Net	60	—	—	60
Operating Revenues and Other ⁽⁴⁾	10,795	182	55	11,032
Depreciation, Depletion and Amortization	3,324	60	16	3,400
Operating Income (Loss) ⁽⁵⁾	(546)	75	(73)	(544)
Interest Income	11	1	—	12
Other Expense	—	(2)	—	(2)
Net Interest Expense	205	—	—	205
Income (Loss) Before Income Taxes	(740)	74	(73)	(739)
Income Tax Provision (Benefit)	(157)	15	8	(134)
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	3,318	83	42	3,443
Total Property, Plant and Equipment, Net	28,284	210	105	28,599
Total Assets	35,048	546	211	35,805

	United States	Trinidad	Other International ⁽¹⁾	Total
2019				
Crude Oil and Condensate	\$ 9,599	\$ 11	\$ 3	\$ 9,613
Natural Gas Liquids	785	—	—	785
Natural Gas	867	259	58	1,184
Gains on Mark-to-Market Commodity Derivative Contracts	180	—	—	180
Gathering, Processing and Marketing	5,355	5	—	5,360
Gains (Losses) on Asset Dispositions, Net	132	(4)	(4)	124
Other, Net	134	—	—	134
Operating Revenues and Other ⁽⁶⁾	17,052	271	57	17,380
Depreciation, Depletion and Amortization	3,652	80	18	3,750
Operating Income (Loss)	3,619	113	(33)	3,699
Interest Income	22	4	—	26
Other Income	3	1	1	5
Net Interest Expense (Income)	192	—	(7)	185
Income (Loss) Before Income Taxes	3,452	118	(25)	3,545
Income Tax Provision	761	41	8	810
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	6,209	53	12	6,274
Total Property, Plant and Equipment, Net	30,102	184	78	30,364
Total Assets	36,275	706	144	37,125

- (1) Other International primarily consists of EOG's China and Canada operations. The China operations were sold in the second quarter of 2021. EOG began exploration programs in Australia in the third quarter of 2021 and in Oman in the third quarter of 2020. The decision was reached in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman.
- (2) EOG had sales activity with two significant purchasers in 2021, one totaling \$2.7 billion and the other totaling \$2.6 billion of consolidated Operating Revenues and Other in the United States segment.
- (3) EOG recorded pretax impairment charges of \$45 million and dry hole costs of \$42 million in 2021 in the Other International segment related to its decision in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman. In addition, EOG recorded net gains of asset dispositions of \$58 million in 2021 in the Other International segment during the second quarter of 2021 due to the sale of its China operations. See Notes 14 and 17, respectively.
- (4) EOG had sales activity with three significant purchasers in 2020, each totaling \$1.1 billion of consolidated Operating Revenues and Other in the United States segment.
- (5) EOG recorded pretax impairment charges of \$1,570 million in 2020 for proved oil and gas properties, leasehold costs and other assets due to the decline in commodity prices and revisions of asset retirement obligations for certain properties in the United States segment. In addition, EOG recorded pretax impairment charges of \$228 million in 2020 for owned and leased sand and crude-by-rail assets, also in the United States segment. EOG recorded pretax impairment charges of \$81 million in 2020 for proved oil and gas properties and firm commitment contracts related to its decision to exit the Horn River Basin in British Columbia, Canada, in the Other International segment. See Notes 13 and 14.
- (6) EOG had sales activity with two significant purchasers in 2019, one totaling \$2.4 billion and the other totaling \$2.2 billion of consolidated Operating Revenues and Other in the United States segment.

12. Risk Management Activities

Commodity Price Transactions. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil, NGLs and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk.

During 2021, 2020 and 2019, EOG elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounted for these financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). The related cash flow impact is reflected in Cash Flows from Operating Activities. During 2021, 2020 and 2019, EOG recognized net gains (losses) on the mark-to-market of financial commodity derivative contracts of \$(1,152) million, \$1,145 million and \$180 million, respectively, which included cash received from (payments for) settlements of crude oil, NGLs and natural gas derivative contracts of \$(638) million, \$1,071 million and \$231 million, respectively.

Presented below is a comprehensive summary of EOG's financial commodity derivative contracts settled during the year ended December 31, 2021 (closed) and remaining for 2022 and thereafter, as of December 31, 2021. Crude oil and NGL volumes are presented in MBbld and prices are presented in \$/Bbl. Natural gas volumes are presented in MMBtu per day (MMBtud) and prices are presented in dollars per MMBtu (\$/MMBtu).

Crude Oil Financial Price Swap Contracts			
Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price (\$/Bbl)
January 2021 (closed)	NYMEX West Texas Intermediate (WTI)	151	\$ 50.06
February - March 2021 (closed)	NYMEX WTI	201	51.29
April - June 2021 (closed)	NYMEX WTI	150	51.68
July - September 2021 (closed)	NYMEX WTI	150	52.71
January - March 2022	NYMEX WTI	140	65.58
April - June 2022	NYMEX WTI	140	65.62
July - September 2022	NYMEX WTI	140	65.59
October - December 2022	NYMEX WTI	140	65.68
January - March 2023	NYMEX WTI	150	67.92
April - June 2023	NYMEX WTI	120	67.79
July - September 2023	NYMEX WTI	20	68.04

Crude Oil Basis Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price Differential (\$/Bbl)
February 2021 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	30	\$ 0.11
March - December 2021 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	125	0.17
January 2022 (closed)	NYMEX WTI Roll Differential ⁽¹⁾	125	0.15
February - December 2022	NYMEX WTI Roll Differential ⁽¹⁾	125	0.15

(1) This settlement index is used to fix the differential in pricing between the NYMEX calendar month average and the physical crude oil delivery month.

NGL Financial Price Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MBbld)	Weighted Average Price (\$/Bbl)
January - December 2021 (closed)	Mont Belvieu Propane (non-Tet)	15	\$ 29.44

Natural Gas Financial Price Swap Contracts

Period	Settlement Index	Contracts Sold		Contracts Purchased	
		Volume (MMBtud in thousands)	Weighted Average Price (\$/MMBtu)	Volume (MMBtud in thousands)	Weighted Average Price (\$/MMBtu)
January - March 2021 (closed)	NYMEX Henry Hub	500	\$ 2.99	500	\$ 2.43
April - September 2021 (closed)	NYMEX Henry Hub	500	2.99	570	2.81
October - December 2021 (closed)	NYMEX Henry Hub	500	2.99	500	2.83
January - December 2022 (closed) ⁽¹⁾	NYMEX Henry Hub	20	2.75	—	—
January - December 2022	NYMEX Henry Hub	725	3.57	—	—
January - December 2023	NYMEX Henry Hub	725	3.18	—	—
January - December 2024	NYMEX Henry Hub	725	3.07	—	—
January - December 2025	NYMEX Henry Hub	725	3.07	—	—
April - September 2021 (closed)	Japan Korea Marker (JKM)	70	6.65	—	—

(1) In January 2021, EOG executed the early termination provision granting EOG the right to terminate all of its 2022 natural gas price swap contracts which were open at that time. EOG received net cash of \$0.6 million for the settlement of these contracts.

Natural Gas Basis Swap Contracts

Period	Settlement Index	Contracts Sold	
		Volume (MMBtu in thousands)	Weighted Average Price (\$/MMBtu)
January - December 2022	NYMEX Henry Hub Houston Ship Channel (HSC) Differential ⁽¹⁾	210	\$ (0.01)
January - December 2023	NYMEX Henry Hub HSC Differential ⁽¹⁾	135	(0.01)
January - December 2024	NYMEX Henry Hub HSC Differential ⁽¹⁾	10	0.00
January - December 2025	NYMEX Henry Hub HSC Differential ⁽¹⁾	10	0.00

(1) This settlement index is used to fix the differential between pricing at the Houston Ship Channel and NYMEX Henry Hub prices.

Commodity Derivatives Location on Balance Sheet. The following table sets forth the amounts and classification of EOG's outstanding derivative financial instruments at December 31, 2021 and 2020, respectively. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

Description	Location on Balance Sheet	Fair Value at December 31,	
		2021	2020
Asset Derivatives			
Crude oil, NGLs and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities	\$ —	\$ 65
Noncurrent portion	Other Assets ⁽¹⁾	6	1
Liability Derivatives			
Crude oil, NGLs and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities ⁽²⁾	\$ 269	\$ —
Noncurrent Portion	Other Liabilities ⁽³⁾	37	1

(1) The noncurrent portion of Assets from Price Risk Management Activities consists of gross assets of \$7 million, partially offset by gross liabilities of \$1 million, at December 31, 2021.

(2) The current portion of Liabilities from Price Risk Management Activities consists of gross liabilities of \$421 million, partially offset by gross assets of \$29 million and collateral posted with counterparties of \$123 million, at December 31, 2021.

(3) The noncurrent portion of Liabilities from Price Risk Management Activities consists of gross liabilities of \$64 million, partially offset by gross assets of \$10 million and collateral posted with counterparties of \$17 million, at December 31, 2021.

Credit Risk. Notional contract amounts are used to express the magnitude of a financial derivative. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 13). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG renegotiates payment terms and/or requires collateral, parent guarantees or letters of credit to minimize credit risk.

At December 31, 2021, EOG's net accounts receivable balance related to United States hydrocarbon sales included three receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from three petroleum refinery companies. The related amounts were collected during early 2022. At December 31, 2020, EOG's net accounts receivable balance related to United States hydrocarbon sales included two receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from two petroleum refinery companies. The related amounts were collected during early 2021.

In 2021 and 2020, all natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary. In 2021 and 2020, all crude oil and condensate from EOG's Trinidad operations was sold to Heritage Petroleum Company Limited. Through May 2021, and in 2020, all natural gas from EOG's China operations was sold to Petrochina Company Limited.

All of EOG's derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 13 for the aggregate fair value of all derivative instruments that were in a net liability position at December 31, 2021 and a net asset position at December 31, 2020. EOG had \$140 million of collateral posted and no collateral held at December 31, 2021, and had no collateral posted or held at December 31, 2020. Due to higher commodity prices subsequent to December 31, 2021, EOG had \$1.4 billion of collateral posted at February 18, 2022.

Substantially all of EOG's accounts receivable at December 31, 2021 and 2020 resulted from hydrocarbon sales and/or joint interest billings to third-party companies, including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer, EOG typically analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2021, credit losses incurred on receivables by EOG have been immaterial.

13. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. An established fair value hierarchy prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. EOG gives consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value.

Recurring Fair Value Measurements. The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at December 31, 2021 and 2020 (in millions):

Fair Value Measurements Using:				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At December 31, 2021				
Financial Assets:				
Natural Gas Swaps	\$ —	\$ 29	\$ —	\$ 29
Natural Gas Basis Swaps	—	2	—	2
Crude Oil Swaps	—	15	—	15
Financial Liabilities:				
Crude Oil Roll Differential Swaps	—	24	—	24
Natural Gas Swaps	—	121	—	121
Crude Oil Swaps	—	340	—	340
Natural Gas Basis Swaps	—	1	—	1
At December 31, 2020				
Financial Assets:				
Natural Gas Swaps	\$ —	\$ 66	\$ —	\$ 66
Financial Liabilities:				
Crude Oil Roll Differential Swaps	—	1	—	1

See Note 12 for the balance sheet amounts and classification of EOG's financial derivative instruments at December 31, 2021 and 2020.

The estimated fair value of crude oil, NGLs and natural gas derivative contracts (including options/collars) was based upon forward commodity price curves based on quoted market prices. Commodity derivative contracts were valued by utilizing an independent third-party derivative valuation provider who uses various types of valuation models, as applicable.

Non-Recurring Fair Value Measurements. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 15.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the group. If the expected undiscounted future cash flows, based on EOG's estimate of (and assumptions regarding) significant Level 3 inputs, including future crude oil, NGLs and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

During 2021, proved oil and gas properties with a carrying amount of \$27 million were written down to their fair value of \$7 million, resulting in pretax impairment charges of \$20 million.

During 2020, due to the decline in commodity prices and revisions of asset retirement obligations for certain properties, proved oil and gas properties with a carrying amount of \$1,587 million were written down to their fair value of \$319 million, resulting in pretax impairment charges of \$1,268 million. In addition, EOG recorded pretax impairment charges in 2020 of \$72 million for a commodity price-related write-down of other assets.

During 2019, proved oil and gas properties with a carrying amount of \$408 million were written down to their fair value of \$201 million, resulting in pretax impairment charges of \$207 million. Included in the \$207 million pretax impairment charges are \$152 million of impairments of proved oil and gas properties for which EOG utilized an accepted offer from a third-party purchaser as the basis for determining fair value. In addition, EOG recorded pretax impairment charges in 2019 of \$90 million for a commodity price-related write-down of other assets.

EOG utilized average prices per acre from comparable market transactions and estimated discounted cash flows as the basis for determining the fair value of unproved and proved properties, respectively, received in non-cash property exchanges. See Note 10.

Fair Value of Debt. At December 31, 2021 and 2020, respectively, EOG had outstanding \$4,890 million and \$5,640 million aggregate principal amount of senior notes, which had estimated fair values of approximately \$5,577 million and \$6,505 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable (Level 2) inputs regarding interest rates available to EOG at year-end.

14. Impairment Expense

Impairment expense was as follows for the years ended December 31, 2021, 2020 and 2019 (in millions):

	2021	2020	2019
Proved properties ⁽¹⁾	\$ 20	\$ 1,268	\$ 207
Unproved properties ⁽²⁾	310	472	220
Other assets ⁽³⁾	28	300	91
Inventories	13	—	—
Firm commitment contracts ⁽⁴⁾	5	60	—
Total	<u>\$ 376</u>	<u>\$ 2,100</u>	<u>\$ 518</u>

(1) Impairments to proved oil and gas properties in 2020 included legacy and non-core natural gas and crude oil and combo plays. Impairments to proved oil and gas properties in 2019 included domestic legacy natural gas assets. See Notes 1 and 13.

(2) Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. Impairments of unproved oil and gas properties included \$38 million in 2021 for the decision in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman. Impairments of unproved oil and gas properties included charges of \$252 million in 2020 for certain leasehold costs that are no longer expected to be developed before expiration in the United States. See Note 1.

(3) Includes impairment charges for owned and leased sand and crude-by-rail assets of \$228 million in 2020 (see Note 18) and a commodity price-related write-down of other assets of \$72 million and \$90 million in 2020 and 2019, respectively (see Note 13).

(4) Includes impairment charges of \$60 million in 2020 for firm commitment contracts related to its decision to exit the Horn River Basin in British Columbia, Canada.

15. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the years ended December 31, 2021 and 2020 (in millions):

	<u>2021</u>	<u>2020</u>
Carrying Amount at Beginning of Period	\$ 1,217	\$ 1,111
Liabilities Incurred	81	58
Liabilities Settled ⁽¹⁾	(131)	(54)
Accretion	44	47
Revisions	20	54
Foreign Currency Translations	—	1
Carrying Amount at End of Period	<u>\$ 1,231</u>	<u>\$ 1,217</u>
Current Portion	\$ 43	\$ 50
Noncurrent Portion	\$ 1,188	\$ 1,167

(1) Includes settlements related to asset sales and property exchanges.

The current and noncurrent portions of EOG's asset retirement obligations are included in Current Liabilities - Other and Other Liabilities, respectively, on the Consolidated Balance Sheets.

16. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the years ended December 31, 2021, 2020 and 2019 are presented below (in millions):

	<u>2021</u>	<u>2020</u>	<u>2019</u>
Balance at January 1	\$ 29	\$ 26	\$ 4
Additions Pending the Determination of Proved Reserves	73	108	83
Reclassifications to Proved Properties	(41)	(81)	(39)
Costs Charged to Expense ⁽¹⁾	(54)	(24)	(22)
Balance at December 31	<u>\$ 7</u>	<u>\$ 29</u>	<u>\$ 26</u>

(1) Includes capitalized exploratory well costs charged to either dry hole costs or impairments.

	<u>2021</u>	<u>2020</u>	<u>2019</u>
Capitalized exploratory well costs that have been capitalized for a period of one year or less	\$ 7	\$ 26	\$ 26
Capitalized exploratory well costs that have been capitalized for a period greater than one year ⁽¹⁾	—	3	—
Balance at December 31	<u>\$ 7</u>	<u>\$ 29</u>	<u>\$ 26</u>
Number of exploratory wells that have been capitalized for a period greater than one year	—	1	—

(1) Consists of costs related to a project in the United States at December 31, 2020.

17. Acquisitions and Divestitures

During 2021, EOG paid cash for property acquisitions of \$95 million in the United States. Additionally during 2021, EOG recognized net gains on asset dispositions of \$17 million and received proceeds of \$231 million primarily due to the sale of the China assets and the disposition of the Northwest Shelf assets in New Mexico. Additionally, in the fourth quarter of 2021, EOG signed a purchase and sale agreement for the sale of primarily producing properties in the Rocky Mountain area. At December 31, 2021, the book value of the assets classified as held for sale and the related asset retirement obligations were \$99 million and \$105 million, respectively.

During 2020, EOG paid cash for property acquisitions of \$82 million in the United States and \$38 million in Other International, primarily in Oman. Additionally during 2020, EOG recognized net losses on asset dispositions of \$47 million primarily due to sales of proved properties and non-cash property exchanges of unproved leasehold in Texas and New Mexico and the disposition of the Marcellus Shale assets, and received proceeds of approximately \$192 million.

During 2019, EOG paid cash for property acquisitions of \$328 million in the United States. Additionally, during 2019, EOG recognized net gains on asset dispositions of \$124 million primarily due to sales of producing properties, acreage and other assets, as well as non-cash property exchanges in New Mexico, and received proceeds of approximately \$140 million.

18. Leases

Lease costs are classified by the function of the ROU asset. The lease costs related to exploration and development activities are initially included in the Oil and Gas Properties line on the Consolidated Balance Sheets and subsequently accounted for in accordance with the Extractive Industries - Oil and Gas Topic of the ASC. Variable lease cost represents costs incurred above the contractual minimum payments and other charges associated with leased equipment, primarily for drilling and fracturing contracts classified as operating leases. The components of lease cost for the years ended December 31, 2021, 2020 and 2019 were as follows (in millions):

	2021	2020	2019
Operating Lease Cost ⁽¹⁾	\$ 295	\$ 393	\$ 497
Finance Lease Cost:			
Amortization of Lease Assets	39	21	13
Interest on Lease Liabilities	7	4	2
Variable Lease Cost	63	91	138
Short-Term Lease Cost	257	194	333
Total Lease Cost	<u>\$ 661</u>	<u>\$ 703</u>	<u>\$ 983</u>

(1) Operating lease cost includes impairment expenses of \$35 million in 2020.

The following table sets forth the amounts and classification of EOG's outstanding ROU assets and related lease liabilities at December 31, 2021 and 2020 and supplemental information for the years ended December 31, 2021 and 2020 (in millions, except lease terms and discount rates):

Description	Location on Balance Sheet	2021	2020
Assets			
Operating Leases	Other Assets	\$ 743	\$ 869
Finance Leases	Property, Plant and Equipment, Net ⁽¹⁾	241	206
Total		\$ 984	\$ 1,075
Liabilities			
Current			
Operating Leases	Current Portion of Operating Lease Liabilities	\$ 240	\$ 295
Finance Leases	Current Portion of Long-Term Debt	37	31
Long-Term			
Operating Leases	Other Liabilities	558	641
Finance Leases	Long-Term Debt	213	181
Total		\$ 1,048	\$ 1,148

(1) Finance lease assets are recorded net of accumulated amortization of \$119 million and \$81 million at December 31, 2021 and 2020, respectively.

	2021	2020
Weighted Average Remaining Lease Term (in years):		
Operating Leases	5.3	5.3
Finance Leases	7.0	7.6
Weighted Average Discount Rate:		
Operating Leases	3.0 %	3.4 %
Finance Leases	2.6 %	2.8 %

Cash paid for leases for the years ended December 31, 2021, 2020 and 2019 was as follows (in millions):

	2021	2020	2019
Repayment of Operating Lease Liabilities Associated with Operating Activities	\$ 207	\$ 223	\$ 225
Repayment of Operating Lease Liabilities Associated with Investing Activities	98	130	270
Repayment of Finance Lease Liabilities	37	19	13

Non-cash leasing activities for the year ended December 31, 2021, included the additions of \$333 million of operating leases and \$74 million of finance leases. Non-cash leasing activities for the year ended December 31, 2020, included the additions of \$893 million of operating leases and \$174 million of finance leases. Non-cash leasing activities for the year ended December 31, 2019, included the addition of \$784 million of operating leases. Upon adoption of ASU 2016-02 effective January 1, 2019, EOG recognized operating lease ROU of \$566 million.

At December 31, 2021, the future minimum lease payments under non-cancellable leases were as follows (in millions):

	Operating Leases	Finance Leases
2022	\$ 262	\$ 42
2023	188	37
2024	113	37
2025	80	36
2026	59	30
2027 and Beyond	172	94
Total Lease Payments	874	276
Less: Discount to Present Value	76	26
Total Lease Liabilities	798	250
Less: Current Portion of Lease Liabilities	240	37
Long-Term Lease Liabilities	\$ 558	\$ 213

At December 31, 2021, EOG had additional leases of \$98 million, which are expected to commence in 2022 with lease terms of three months to nine years.

EOG RESOURCES, INC.
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
(In Millions, Except Per Share Data, Unless Otherwise Indicated)
(Unaudited)

Oil and Gas Producing Activities

The following disclosures are made in accordance with Financial Accounting Standards Board Accounting Standards Update No. 2010-03 "Oil and Gas Reserve Estimation and Disclosures" and the United States Securities and Exchange Commission's (SEC) final rule on "Modernization of Oil and Gas Reporting."

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil, natural gas liquids (NGLs) and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity; evolving production history; crude oil and condensate, NGL and natural gas prices; and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of crude oil, NGLs and natural gas, which, by analysis of geoscience and engineering data, can be estimated, with reasonable certainty, to be economically producible from a given date forward from known reservoirs under then-existing economic conditions, operating methods and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion or recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. PUDs can be recorded in respect of a particular undrilled location only if the location is scheduled, under the then-current drilling and development plan, to be drilled within five years from the date that the PUDs were recorded, unless specific factors (such as those described in interpretative guidance issued by the Staff of the SEC) justify a longer timeframe. Likewise, absent any such specific factors, PUDs associated with a particular undeveloped drilling location shall be removed from the estimates of proved reserves if the location is scheduled, under the then-current drilling and development plan, to be drilled on a date that is beyond five years from the date that the PUDs were recorded. EOG has formulated development plans for all drilling locations associated with its PUDs at December 31, 2021. Under these plans, each PUD location will be drilled within five years from the date it was recorded. Estimates for PUDs are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

In making estimates of PUDs, EOG's technical staff, including engineers and geoscientists, perform detailed technical analysis of each potential drilling location within its inventory of prospects. In making a determination as to which of these locations would penetrate undrilled portions of the formation that can be judged, with reasonable certainty, to be continuous and contain economically producible crude oil, NGLs and natural gas, studies are conducted using numerous data elements and analysis techniques. EOG's technical staff estimates the hydrocarbons in place, by mapping the entirety of the play in question using seismic techniques, typically employing two-dimensional and three-dimensional data. This analysis is integrated with other static data, including, but not limited to, core analysis, mechanical properties of the formation, thermal maturity indicators, and well logs of existing penetrations. Highly specialized equipment is utilized to prepare rock samples in assessing microstructures which contribute to porosity and permeability.

Analysis of dynamic data is then incorporated to arrive at the estimated fractional recovery of hydrocarbons in place. Data analysis techniques employed include, but are not limited to, well testing analysis, static bottom hole pressure analysis, flowing bottom hole pressure analysis, analysis of historical production trends, pressure transient analysis and rate transient analysis. Application of proprietary rate transient analysis techniques in low permeability rocks allow for quantification of estimates of contribution to production from both fractures and rock matrix.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The impact of optimal completion techniques is a key factor in determining if the PUDs reflected in prospective locations are reasonably certain of being economically producible. EOG's technical staff estimates the recovery improvement that might be achieved when completing horizontal wells with multi-stage fracture stimulation. In the early stages of development of a play, EOG determines the optimal length of the horizontal lateral and multi-stage fracture stimulation using the aforementioned analysis techniques along with pilot drilling programs and gathering of microseismic data.

The process of analyzing static and dynamic data, well completion optimization data and the results of early development activities provides the appropriate level of certainty as well as support for the economic producibility of the plays in which PUDs are reflected. EOG has found this approach to be effective based on successful application in analogous reservoirs in low permeability resource plays.

Certain of EOG's Trinidad reserves are held under production sharing contracts where EOG's interest varies with prices and production volumes. Trinidad reserves, as presented on a net basis, assume prices in existence at the time the estimates were made and EOG's estimate of future production volumes. Future fluctuations in prices, production rates or changes in political or regulatory environments could cause EOG's share of future production from Trinidadian reserves to be materially different from that presented.

Estimates of proved reserves at December 31, 2021, 2020 and 2019 were based on studies performed by the engineering staff of EOG. The Engineering and Acquisitions Department is directly responsible for EOG's reserve evaluation process and consists of 18 professionals, all of whom hold, at a minimum, bachelor's degrees in engineering, and three of whom are Registered Professional Engineers. The Vice President, Engineering and Acquisitions is the manager of this department and is the primary technical person responsible for this process. The Vice President, Engineering and Acquisitions holds a Bachelor of Science degree in Petroleum Engineering, has 35 years of experience in reserve evaluations and is a Registered Professional Engineer.

EOG's reserves estimation process is a collaborative effort coordinated by the Engineering and Acquisitions Department in compliance with EOG's internal controls for such process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including crude oil, NGL and natural gas prices, production costs, transportation costs, processing and applicable fractionation costs, future capital expenditures and EOG's net ownership percentages, are obtained from other departments within EOG. EOG's Internal Audit Department conducts testing with respect to such non-technical inputs. Additionally, EOG engages DeGolyer and MacNaughton (D&M), independent petroleum consultants, to perform independent reserves evaluation of select EOG properties comprising not less than 75% of EOG's estimates of proved reserves. EOG's Board of Directors requires that D&M's and EOG's reserve quantities for the properties evaluated by D&M vary by no more than 5% in the aggregate. Once completed, EOG's year-end reserves are presented to senior management, including the Chief Executive Officer; the President and Chief Operating Officer; the Executive Vice Presidents, Exploration and Production; and the Executive Vice President and Chief Financial Officer, for approval.

Opinions by D&M for the years ended December 31, 2021, 2020 and 2019 covered producing areas containing 78%, 83% and 82%, respectively, of proved reserves of EOG on a net-equivalent-barrel-of-oil basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's Engineering and Acquisitions Department for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil basis, do not differ materially from the estimates prepared by D&M. Specifically, such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the Engineering and Acquisitions Department of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG. The report of D&M dated January 27, 2022, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 99.1 to this Annual Report on Form 10-K and incorporated herein by reference.

No major discovery or other favorable or adverse event subsequent to December 31, 2021, is believed to have caused a material change in the estimates of net proved reserves as of that date.

The following tables set forth EOG's net proved reserves at December 31 for each of the four years in the period ended December 31, 2021, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2021, as estimated by the Engineering and Acquisitions Department of EOG:

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NET PROVED RESERVE SUMMARY

	United States	Trinidad	Other International ⁽¹⁾	Total
<u>NET PROVED RESERVES</u>				
Crude Oil (MMBbl) ⁽²⁾				
Net proved reserves at December 31, 2018	1,532	—	—	1,532
Revisions of previous estimates	(43)	—	—	(43)
Purchases in place	3	—	—	3
Extensions, discoveries and other additions	370	—	—	370
Sales in place	(1)	—	—	(1)
Production	(167)	—	—	(167)
Net proved reserves at December 31, 2019	1,694	—	—	1,694
Revisions of previous estimates	(225)	—	—	(225)
Purchases in place	2	—	—	2
Extensions, discoveries and other additions	194	1	—	195
Sales in place	(3)	—	—	(3)
Production	(149)	—	—	(149)
Net proved reserves at December 31, 2020	1,513	1	—	1,514
Revisions of previous estimates	(116)	—	—	(116)
Purchases in place	2	—	—	2
Extensions, discoveries and other additions	311	1	—	312
Sales in place	(2)	—	—	(2)
Production	(162)	—	—	(162)
Net proved reserves at December 31, 2021	1,546	2	—	1,548
Natural Gas Liquids (MMBbl) ⁽²⁾				
Net proved reserves at December 31, 2018	614	—	—	614
Revisions of previous estimates	5	—	—	5
Purchases in place	2	—	—	2
Extensions, discoveries and other additions	168	—	—	168
Sales in place	(1)	—	—	(1)
Production	(48)	—	—	(48)
Net proved reserves at December 31, 2019	740	—	—	740
Revisions of previous estimates	(60)	—	—	(60)
Purchases in place	4	—	—	4
Extensions, discoveries and other additions	180	—	—	180
Sales in place	(1)	—	—	(1)
Production	(50)	—	—	(50)
Net proved reserves at December 31, 2020	813	—	—	813
Revisions of previous estimates	(128)	—	—	(128)
Purchases in place	3	—	—	3
Extensions, discoveries and other additions	194	—	—	194
Sales in place	—	—	—	—
Production	(53)	—	—	(53)
Net proved reserves at December 31, 2021	829	—	—	829

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Trinidad	Other International ⁽¹⁾	Total
Natural Gas (Bcf) ⁽³⁾				
Net proved reserves at December 31, 2018	4,391	237	59	4,687
Revisions of previous estimates	(184)	47	3	(134)
Purchases in place	72	—	—	72
Extensions, discoveries and other additions	1,176	87	10	1,273
Sales in place	(15)	—	—	(15)
Production	(405)	(95)	(13)	(513)
Net proved reserves at December 31, 2019	5,035	276	59	5,370
Revisions of previous estimates	(498)	5	1	(492)
Purchases in place	26	—	—	26
Extensions, discoveries and other additions	1,078	54	—	1,132
Sales in place	(157)	—	—	(157)
Production	(441)	(66)	(12)	(519)
Net proved reserves at December 31, 2020	5,043	269	48	5,360
Revisions of previous estimates	754	26	3	783
Purchases in place	23	—	—	23
Extensions, discoveries and other additions	2,574	100	—	2,674
Sales in place	(4)	—	(48)	(52)
Production	(483)	(80)	(3)	(566)
Net proved reserves at December 31, 2021	7,907	315	—	8,222
Oil Equivalents (MMBoe) ⁽²⁾				
Net proved reserves at December 31, 2018	2,878	40	10	2,928
Revisions of previous estimates	(68)	8	—	(60)
Purchases in place	17	—	—	17
Extensions, discoveries and other additions	734	14	2	750
Sales in place	(5)	—	—	(5)
Production	(283)	(16)	(2)	(301)
Net proved reserves at December 31, 2019	3,273	46	10	3,329
Revisions of previous estimates	(368)	1	—	(367)
Purchases in place	10	—	—	10
Extensions, discoveries and other additions	554	10	—	564
Sales in place	(31)	—	—	(31)
Production	(272)	(11)	(2)	(285)
Net proved reserves at December 31, 2020	3,166	46	8	3,220
Revisions of previous estimates	(118)	4	—	(114)
Purchases in place	9	—	—	9
Extensions, discoveries and other additions	934	18	—	952
Sales in place	(3)	—	(8)	(11)
Production	(295)	(14)	—	(309)
Net proved reserves at December 31, 2021	3,693	54	—	3,747

(1) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

(2) Million barrels or million barrels of oil equivalent, as applicable; oil equivalents include crude oil and condensate, NGLs and natural gas. Oil equivalents are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas.

(3) Billion cubic feet.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2021, EOG added 952 million barrels of oil equivalent (MMBoe) of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin. Approximately 53% of the 2021 reserve additions were crude oil and condensate and NGLs, and substantially all were in the United States. Sales in place of 11 MMBoe were primarily related to the sale of the China assets and the sale or exchange of other producing assets. Revisions of previous estimates of negative 114 MMBoe for 2021 included an upward revision of 194 MMBoe primarily due to increases in the average crude oil, NGLs and natural gas prices used in the December 31, 2021, reserves estimation as compared to the prices used in the prior year estimate. The primary areas affected were the Permian Basin and the Rocky Mountain area. Revisions other than price of negative 308 MMBoe were primarily related to the removal from the five-year development plan of certain PUD locations. These locations were replaced with more economic locations in the Permian Basin and the Dorado gas play, and the related reserves from these locations were included as extensions, discoveries and other additions. Purchases in place of 9 MMBoe were primarily related to the Permian Basin and the purchase or exchange of other producing assets.

During 2020, EOG added 564 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin. Approximately 67% of the 2020 reserve additions were crude oil and condensate and NGLs, and substantially all were in the United States. Sales in place of 31 MMBoe were primarily related to the sale of the Marcellus Shale assets and the sale or exchange of other producing assets. Revisions of previous estimates of negative 367 MMBoe for 2020 included a downward revision of 278 MMBoe primarily due to decreases in the average crude oil, NGLs and natural gas prices used in the December 31, 2020, reserves estimation as compared to the prices used in the prior year estimate. The primary areas affected were the Eagle Ford oil play and the Rocky Mountain area. Purchases in place of 10 MMBoe were primarily related to the Permian Basin and the purchase or exchange of other producing assets.

During 2019, EOG added 750 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin, the Eagle Ford oil play and the Rocky Mountain area. Approximately 72% of the 2019 reserve additions were crude oil and condensate and NGLs, and substantially all were in the United States. Sales in place of 5 MMBoe were primarily related to the sale of certain South Texas area operations and the sale or exchange of other producing assets. Revisions of previous estimates of negative 60 MMBoe for 2019 included a decrease in the average crude oil, NGLs and natural gas prices used in the December 31, 2019, reserves estimation as compared to the prices used in the prior year estimate. The primary area affected was the Rocky Mountain area. Purchases in place of 17 MMBoe were primarily related to the South Texas area.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Trinidad	Other International ⁽¹⁾	Total
<u>NET PROVED DEVELOPED RESERVES</u>				
Crude Oil (MMBbl)				
December 31, 2018	713	—	—	713
December 31, 2019	801	—	—	801
December 31, 2020	792	1	—	793
December 31, 2021	886	—	—	886
Natural Gas Liquids (MMBbl)				
December 31, 2018	341	—	—	341
December 31, 2019	387	—	—	387
December 31, 2020	392	—	—	392
December 31, 2021	416	—	—	416
Natural Gas (Bcf)				
December 31, 2018	2,699	224	41	2,964
December 31, 2019	2,974	178	42	3,194
December 31, 2020	2,586	171	32	2,789
December 31, 2021	3,743	131	—	3,874
Oil Equivalents (MMBoe)				
December 31, 2018	1,503	38	7	1,548
December 31, 2019	1,684	30	7	1,721
December 31, 2020	1,614	30	5	1,649
December 31, 2021	1,926	22	—	1,948
<u>NET PROVED UNDEVELOPED RESERVES</u>				
Crude Oil (MMBbl)				
December 31, 2018	819	—	—	819
December 31, 2019	893	—	—	893
December 31, 2020	721	—	—	721
December 31, 2021	660	2	—	662
Natural Gas Liquids (MMBbl)				
December 31, 2018	273	—	—	273
December 31, 2019	353	—	—	353
December 31, 2020	421	—	—	421
December 31, 2021	413	—	—	413
Natural Gas (Bcf)				
December 31, 2018	1,692	13	18	1,723
December 31, 2019	2,061	98	17	2,176
December 31, 2020	2,457	98	16	2,571
December 31, 2021	4,164	184	—	4,348
Oil Equivalents (MMBoe)				
December 31, 2018	1,375	2	3	1,380
December 31, 2019	1,589	16	3	1,608
December 31, 2020	1,552	16	3	1,571
December 31, 2021	1,767	32	—	1,799

(1) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net Proved Undeveloped Reserves. The following table presents the changes in EOG's total PUDs during 2021, 2020 and 2019 (in MMBoe):

	2021	2020	2019
Balance at January 1	1,571	1,608	1,380
Extensions and Discoveries	779	456	578
Revisions	(305)	(277)	(50)
Acquisition of Reserves	—	—	2
Sale of Reserves	(3)	(4)	—
Conversion to Proved Developed Reserves	(243)	(212)	(302)
Balance at December 31	1,799	1,571	1,608

For the twelve-month period ended December 31, 2021, total PUDs increased by 228 MMBoe to 1,799 MMBoe. EOG added approximately 40 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on pages F-39 and F-40 of this Annual Report on Form 10-K), EOG added 739 MMBoe of PUDs. The PUD additions were primarily in the Permian Basin and 52% of the additions were crude oil and condensate and NGLs. During 2021, EOG drilled and transferred 243 MMBoe of PUDs to proved developed reserves at a total capital cost of \$1,619 million. Revisions of previous estimates of negative 305 MMBoe of PUDs for 2021 included an upward price revision of 29 MMBoe due to increases in the average crude oil, NGLs and natural gas prices used in the December 31, 2021, reserves estimation as compared to the prices used in the prior year estimate. Revisions other than price of negative 334 MMBoe were primarily related to the removal from the five-year development plan of certain PUD locations. These locations were replaced with more economic locations in the Permian Basin and the Dorado gas play, and the related reserves from these locations were included as extensions and discoveries. All PUDs, including drilled but uncompleted wells (DUCs), are scheduled for completion within five years of the original reserve booking.

For the twelve-month period ended December 31, 2020, total PUDs decreased by 37 MMBoe to 1,571 MMBoe. EOG added approximately 7 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 449 MMBoe of PUDs. The PUD additions were primarily in the Permian Basin and 67% of the additions were crude oil and condensate and NGLs. During 2020, EOG drilled and transferred 212 MMBoe of PUDs to proved developed reserves at a total capital cost of \$1,674 million. Revisions of previous estimates of negative 277 MMBoe of PUDs for 2020 included a downward price revision of 77 MMBoe due to decreases in the average crude oil, NGLs and natural gas prices used in the December 31, 2020, reserves estimation as compared to the prices used in the prior year estimate. Revisions other than price of negative 200 MMBoe were primarily related to the removal of PUD locations due to lower projected capital spending over the next five years as compared to the prior year projections. The primary areas affected were the Eagle Ford oil play and the Rocky Mountain area.

For the twelve-month period ended December 31, 2019, total PUDs increased by 228 MMBoe to 1,608 MMBoe. EOG added approximately 38 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 540 MMBoe. The PUD additions were primarily in the Permian Basin, the Eagle Ford oil play and, to a lesser extent, the Rocky Mountain area, and 73% of the additions were crude oil and condensate and NGLs. During 2019, EOG drilled and transferred 302 MMBoe of PUDs to proved developed reserves at a total capital cost of \$3,032 million.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's crude oil, NGLs and natural gas producing activities at December 31, 2021 and 2020:

	<u>2021</u>	<u>2020</u>
Proved properties	\$ 64,876	\$ 61,725
Unproved properties	2,768	3,068
Total	<u>67,644</u>	<u>64,793</u>
Accumulated depreciation, depletion and amortization	(41,907)	(38,751)
Net capitalized costs	<u><u>\$ 25,737</u></u>	<u><u>\$ 26,042</u></u>

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in the Extractive Industries - Oil and Gas Topic of the Accounting Standards Codification (ASC).

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property.

Exploration costs include additions to exploratory wells, including those in progress, and exploration expenses.

Development costs include additions to production facilities and equipment and additions to development wells, including those in progress.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2021, 2020 and 2019:

	United States	Trinidad	Other International ⁽¹⁾	Total
2021				
Acquisition Costs of Properties				
Unproved ⁽²⁾	\$ 207	\$ —	\$ 8	\$ 215
Proved ⁽³⁾	100	—	—	100
Subtotal	307	—	8	315
Exploration Costs	296	7	51	354
Development Costs ⁽⁴⁾	3,206	77	17	3,300
Total	<u>\$ 3,809</u>	<u>\$ 84</u>	<u>\$ 76</u>	<u>\$ 3,969</u>
2020				
Acquisition Costs of Properties				
Unproved ⁽⁵⁾	\$ 265	\$ —	\$ —	\$ 265
Proved ⁽⁶⁾	97	—	38	135
Subtotal	362	—	38	400
Exploration Costs	203	81	12	296
Development Costs ⁽⁷⁾	2,998	4	20	3,022
Total	<u>\$ 3,563</u>	<u>\$ 85</u>	<u>\$ 70</u>	<u>\$ 3,718</u>
2019				
Acquisition Costs of Properties				
Unproved ⁽⁸⁾	\$ 276	\$ —	\$ —	\$ 276
Proved ⁽⁹⁾	380	—	—	380
Subtotal	656	—	—	656
Exploration Costs	214	47	12	273
Development Costs ⁽¹⁰⁾	5,662	25	12	5,699
Total	<u>\$ 6,532</u>	<u>\$ 72</u>	<u>\$ 24</u>	<u>\$ 6,628</u>

(1) Other International primarily consists of EOG's China and Canada operations. The China operations were sold in the second quarter of 2021. EOG began exploration programs in Australia in the third quarter of 2021 and in Oman in the third quarter of 2020. The decision was reached in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman.

(2) Includes non-cash unproved leasehold acquisition costs of \$45 million related to property exchanges.

(3) Includes non-cash proved property acquisition costs of \$5 million related to property exchanges.

(4) Includes Asset Retirement Costs of \$86 million, \$24 million and \$17 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

(5) Includes non-cash unproved leasehold acquisition costs of \$197 million related to property exchanges.

(6) Includes non-cash proved property acquisition costs of \$15 million related to property exchanges.

(7) Includes Asset Retirement Costs of \$97 million and \$20 million for the United States and Other International, respectively. Excludes other property, plant and equipment.

(8) Includes non-cash unproved leasehold acquisition costs of \$98 million related to property exchanges.

(9) Includes non-cash proved property acquisition costs of \$52 million related to property exchanges.

(10) Includes Asset Retirement Costs of \$181 million, \$1 million and \$4 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations for Oil and Gas Producing Activities ⁽¹⁾. The following table sets forth results of operations for oil and gas producing activities for the years ended December 31, 2021, 2020 and 2019:

	United States	Trinidad	Other International ⁽²⁾	Total
2021				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	\$ 15,062	\$ 301	\$ 18	\$ 15,381
Other	108	—	—	108
Total	15,170	301	18	15,489
Exploration Costs	137	5	12	154
Dry Hole Costs	29	—	42	71
Transportation Costs	863	—	—	863
Gathering and Processing Costs	559	—	—	559
Production Costs	2,108	39	8	2,155
Impairments	312	3	61	376
Depreciation, Depletion and Amortization	3,411	87	6	3,504
Income (Loss) Before Income Taxes	7,751	167	(111)	7,807
Income Tax Provision	1,690	73	(1)	1,762
Results of Operations	<u>\$ 6,061</u>	<u>\$ 94</u>	<u>\$ (110)</u>	<u>\$ 6,045</u>
2020				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	\$ 7,056	\$ 180	\$ 55	\$ 7,291
Other	60	—	—	60
Total	7,116	180	55	7,351
Exploration Costs	136	2	8	146
Dry Hole Costs	13	—	—	13
Transportation Costs	734	1	—	735
Gathering and Processing Costs	459	—	—	459
Production Costs	1,480	27	10	1,517
Impairments	2,018	1	81	2,100
Depreciation, Depletion and Amortization	3,192	60	16	3,268
Income (Loss) Before Income Taxes	(916)	89	(60)	(887)
Income Tax Provision	(220)	24	3	(193)
Results of Operations	<u>\$ (696)</u>	<u>\$ 65</u>	<u>\$ (63)</u>	<u>\$ (694)</u>
2019				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	\$ 11,251	\$ 270	\$ 61	\$ 11,582
Other	134	—	—	134
Total	11,385	270	61	11,716
Exploration Costs	130	4	6	140
Dry Hole Costs	11	13	4	28
Transportation Costs	753	4	1	758
Gathering and Processing Costs	479	—	—	479
Production Costs	2,063	31	40	2,134
Impairments	511	6	1	518
Depreciation, Depletion and Amortization	3,561	79	18	3,658
Income (Loss) Before Income Taxes	3,877	133	(9)	4,001
Income Tax Provision	884	55	3	942
Results of Operations	<u>\$ 2,993</u>	<u>\$ 78</u>	<u>\$ (12)</u>	<u>\$ 3,059</u>

(1) Excludes gains or losses on the mark-to-market of financial commodity derivative contracts, gains or losses on sales of reserves and related assets, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2021.

(2) Other International primarily consists of EOG's China and Canada operations. The China operations were sold in the second quarter of 2021. EOG began exploration programs in Australia in the third quarter of 2021 and in Oman in the third quarter of 2020. The decision was reached in the fourth quarter of 2021 to exit Block 36 and Block 49 in Oman.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth production costs per barrel of oil equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2021, 2020 and 2019:

	United States	Trinidad	Other International ⁽¹⁾	Composite
Year Ended December 31, 2021	\$ 3.71	\$ 2.32	\$ 16.13	\$ 3.67
Year Ended December 31, 2020	\$ 3.75	\$ 2.33	\$ 6.78	\$ 3.72
Year Ended December 31, 2019	\$ 4.59	\$ 1.85	\$ 18.26	\$ 4.54

(1) Other International primarily consists of EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by the Extractive Industries - Oil and Gas Topic of the ASC and based on crude oil, NGL and natural gas reserves and production volumes estimated by the Engineering and Acquisitions Department of EOG. The estimates were based on a 12-month average for commodity prices for the years 2021, 2020 and 2019. The following information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil, NGL and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible reserves as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's oil and gas reserves for the years ended December 31, 2021, 2020 and 2019:

	United States	Trinidad	Other International ⁽¹⁾	Total
2021				
Future cash inflows ⁽²⁾	\$ 166,316	\$ 1,135	\$ —	\$ 167,451
Future production costs	(44,905)	(258)	—	(45,163)
Future development costs	(13,885)	(380)	—	(14,265)
Future income taxes	(22,831)	(84)	—	(22,915)
Future net cash flows	84,695	413	—	85,108
Discount to present value at 10% annual rate	(38,834)	(88)	—	(38,922)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	<u>\$ 45,861</u>	<u>\$ 325</u>	<u>\$ —</u>	<u>\$ 46,186</u>
2020				
Future cash inflows ⁽³⁾	\$ 73,727	\$ 901	\$ 281	\$ 74,909
Future production costs	(34,619)	(153)	(54)	(34,826)
Future development costs	(15,159)	(227)	(18)	(15,404)
Future income taxes	(4,337)	(81)	(24)	(4,442)
Future net cash flows	19,612	440	185	20,237
Discount to present value at 10% annual rate	(8,410)	(101)	(36)	(8,547)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	<u>\$ 11,202</u>	<u>\$ 339</u>	<u>\$ 149</u>	<u>\$ 11,690</u>
2019				
Future cash inflows ⁽⁴⁾	\$ 120,360	\$ 813	\$ 305	\$ 121,478
Future production costs	(42,387)	(166)	(88)	(42,641)
Future development costs	(20,356)	(212)	(18)	(20,586)
Future income taxes	(11,460)	(74)	(32)	(11,566)
Future net cash flows	46,157	361	167	46,685
Discount to present value at 10% annual rate	(21,043)	(86)	(35)	(21,164)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	<u>\$ 25,114</u>	<u>\$ 275</u>	<u>\$ 132</u>	<u>\$ 25,521</u>

(1) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

(2) Estimated crude oil prices used to calculate 2021 future cash inflows for the United States and Trinidad were \$67.79 and \$58.32, respectively. Estimated NGL price used to calculate 2021 future cash inflows for the United States was \$30.28. Estimated natural gas prices used to calculate 2021 future cash inflows for the United States and Trinidad were \$4.61 and \$3.28, respectively.

(3) Estimated crude oil prices used to calculate 2020 future cash inflows for the United States, Trinidad and Other International were \$37.19, \$26.75, and \$41.87, respectively. Estimated NGL price used to calculate 2020 future cash inflows for the United States was \$12.47. Estimated natural gas prices used to calculate 2020 future cash inflows for the United States, Trinidad and Other International were \$1.45, \$3.28, and \$5.65, respectively.

(4) Estimated crude oil prices used to calculate 2019 future cash inflows for the United States, Trinidad and Other International were \$57.51, \$46.77 and \$57.22, respectively. Estimated NGL price used to calculate 2019 future cash inflows for the United States was \$16.91. Estimated natural gas prices used to calculate 2019 future cash inflows for the United States, Trinidad and Other International were \$2.07, \$2.90 and \$5.01, respectively.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2021:

	United States	Trinidad	Other International ⁽¹⁾	Total
December 31, 2018	\$ 32,033	\$ 266	\$ 127	\$ 32,426
Sales and transfers of oil and gas produced, net of production costs	(7,955)	(235)	(20)	(8,210)
Net changes in prices and production costs	(10,974)	66	28	(10,880)
Extensions, discoveries, additions and improved recovery, net of related costs	5,608	85	16	5,709
Development costs incurred	3,004	23	6	3,033
Revisions of estimated development cost	(599)	(129)	(11)	(739)
Revisions of previous quantity estimates	(813)	116	1	(696)
Accretion of discount	3,892	43	15	3,950
Net change in income taxes	1,454	94	1	1,549
Purchases of reserves in place	99	—	—	99
Sales of reserves in place	(51)	—	—	(51)
Changes in timing and other	(584)	(54)	(31)	(669)
December 31, 2019	\$ 25,114	\$ 275	\$ 132	\$ 25,521
Sales and transfers of oil and gas produced, net of production costs	(4,382)	(152)	(45)	(4,579)
Net changes in prices and production costs	(18,625)	132	47	(18,446)
Extensions, discoveries, additions and improved recovery, net of related costs	1,437	64	—	1,501
Development costs incurred	1,675	—	—	1,675
Revisions of estimated development cost	4,149	(11)	—	4,138
Revisions of previous quantity estimates	(3,307)	12	(2)	(3,297)
Accretion of discount	3,055	34	15	3,104
Net change in income taxes	3,497	(12)	3	3,488
Purchases of reserves in place	49	—	—	49
Sales of reserves in place	(156)	—	—	(156)
Changes in timing and other	(1,304)	(3)	(1)	(1,308)
December 31, 2020	\$ 11,202	\$ 339	\$ 149	\$ 11,690
Sales and transfers of oil and gas produced, net of production costs	(11,532)	(261)	(16)	(11,809)
Net changes in prices and production costs	37,088	133	(1)	37,220
Extensions, discoveries, additions and improved recovery, net of related costs	12,154	71	—	12,225
Development costs incurred	1,619	16	—	1,635
Revisions of estimated development cost	2,773	(133)	—	2,640
Revisions of previous quantity estimates	(1,789)	73	—	(1,716)
Accretion of discount	1,313	42	17	1,372
Net change in income taxes	(9,914)	27	17	(9,870)
Purchases of reserves in place	151	—	—	151
Sales of reserves in place	(19)	—	(151)	(170)
Changes in timing and other	2,815	18	(15)	2,818
December 31, 2021	\$ 45,861	\$ 325	\$ —	\$ 46,186

(1) Other International includes EOG's China and Canada operations. The China operations were sold in the second quarter of 2021.

EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by (i) an asterisk (*) and are filed herewith; or (ii) a pound sign (#) and are not filed herewith, and, pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the registrant hereby agrees to furnish a copy of such exhibit to the United States Securities and Exchange Commission (SEC) upon request.

<u>Exhibit Number</u>	<u>Description</u>
3.1(a)	- Restated Certificate of Incorporation, dated September 3, 1987 (Exhibit 3.1(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
3.1(b)	- Certificate of Amendment of Restated Certificate of Incorporation, dated May 5, 1993 (Exhibit 4.1(b) to EOG's Registration Statement on Form S-8, SEC File No. 33-52201, filed February 8, 1994).
3.1(c)	- Certificate of Amendment of Restated Certificate of Incorporation, dated June 14, 1994 (Exhibit 4.1(c) to EOG's Registration Statement on Form S-8, SEC File No. 33-58103, filed March 15, 1995).
3.1(d)	- Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to EOG's Registration Statement on Form S-3, SEC File No. 333-09919, filed August 9, 1996).
3.1(e)	- Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to EOG's Registration Statement on Form S-3, SEC File No. 333-44785, filed January 23, 1998).
3.1(f)	- Certificate of Ownership and Merger Merging EOG Resources, Inc. into Enron Oil & Gas Company, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
3.1(g)	- Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to EOG's Registration Statement on Form 8-A, SEC File No. 001-09743, filed February 18, 2000).
3.1(h)	- Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 13, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(i)	- Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 13, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(j)	- Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004) (SEC File No. 001-09743).
3.1(k)	- Amended Certificate of Designations of Series E Junior Participating Preferred Stock, dated March 7, 2005 (Exhibit 3.1(m) to EOG's Annual Report on Form 10-K for the year ended December 31, 2007) (SEC File No. 001-09743).
3.1(l)	- Certificate of Amendment of Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005) (SEC File No. 001-09743).
3.1(m)	- Certificate of Elimination of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated March 6, 2008 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed March 6, 2008) (SEC File No. 001-09743).
3.1(n)	- Certificate of Amendment of Restated Certificate of Incorporation, dated April 28, 2017 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed May 2, 2017) (SEC File No. 001-09743).
3.2	- Bylaws, dated August 23, 1989, as amended and restated effective as of September 22, 2015 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed September 28, 2015) (SEC File No. 001-09743).
4.1	- Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934 (Exhibit 4.1 to EOG's Annual Report on Form 10-K for the year ended December 31, 2019) (SEC File No. 001-09743).
4.2	- Indenture, dated as of September 1, 1991, between Enron Oil & Gas Company (predecessor to EOG) and The Bank of New York Mellon Trust Company, N.A. (as successor in interest to JPMorgan Chase Bank, N.A. (formerly, Texas Commerce Bank National Association)), as Trustee (Exhibit 4(a) to EOG's Registration Statement on Form S-3, SEC File No. 33-42640, filed in paper format on September 6, 1991).

<u>Exhibit Number</u>	<u>Description</u>
#4.3(a)	- Certificate, dated April 3, 1998, of the Senior Vice President and Chief Financial Officer of Enron Oil & Gas Company (predecessor to EOG) establishing the terms of the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company.
#4.3(b)	- Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
4.4	- Indenture, dated as of May 18, 2009, between EOG and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as Trustee (Exhibit 4.9 to EOG's Registration Statement on Form S-3, SEC File No. 333-159301, filed May 18, 2009).
4.5(a)	- Officers' Certificate Establishing 2.625% Senior Notes due 2023 of EOG, dated September 10, 2012 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 11, 2012) (SEC File No. 001-09743).
4.5(b)	- Form of Global Note with respect to the 2.625% Senior Notes due 2023 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 11, 2012) (SEC File No. 001-09743).
4.6(a)	- Officers' Certificate Establishing 3.15% Senior Notes due 2025 and 3.90% Senior Notes due 2035 of EOG, dated March 17, 2015 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.6(b)	- Form of Global Note with respect to the 3.15% Senior Notes due 2025 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.6(c)	- Form of Global Note with respect to the 3.90% Senior Notes due 2035 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.7(a)	- Officers' Certificate Establishing 4.15% Senior Notes due 2026 and 5.10% Senior Notes due 2036 of EOG, dated January 14, 2016 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).
4.7(b)	- Form of Global Note with respect to the 4.15% Senior Notes due 2026 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).
4.7(c)	- Form of Global Note with respect to the 5.10% Senior Notes due 2036 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).
4.8(a)	- Officers' Certificate Establishing 4.375% Senior Notes due 2030 and 4.950% Senior Notes due 2050 of EOG, dated April 14, 2020 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed April 14, 2020) (SEC File No. 001-09743).
4.8(b)	- Form of Global Note with respect to the 4.375% Senior Notes due 2030 of EOG (included in Exhibit 4.10(a)).
4.8(c)	- Form of Global Note with respect to the 4.950% Senior Notes due 2050 of EOG (included in Exhibit 4.10(a)).
10.1(a)+	- Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 2, 2013 (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.1(b)+	- Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.5 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.1(c)+	- Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 27, 2018 and prior to September 28, 2020) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018) (SEC File No. 001-09743).
10.1(d)+	- Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 28, 2020) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020) (SEC File No. 001-09743).
10.1(e)+	- Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.6 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).

<u>Exhibit Number</u>	<u>Description</u>
10.1(f)+	Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 27, 2018 and prior to September 28, 2020) (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018) (SEC File No. 001-09743).
10.1(g)+	- Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 28, 2020) (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020) (SEC File No. 001-09743).
10.1(h)+	- Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.7 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.1(i)+	- Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 25, 2017 and prior to September 28, 2020) (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 29, 2017) (SEC File No. 001-09743).
10.1(j)+	- Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 28, 2020) (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020) (SEC File No. 001-09743).
10.1(k)+	- Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 27, 2018 and prior to September 26, 2019) (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018) (SEC File No. 001-09743).
10.1(l)+	- Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 26, 2019 and prior to September 28, 2020) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019) (SEC File No. 001-09743).
10.1(m)+	- Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after September 28, 2020) (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020) (SEC File No. 001-09743).
10.1(n)+	- Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grant made to Ezra Y. Yacob effective January 4, 2021) (Exhibit 10.1(u) to EOG's Annual Report on Form 10-K for the year ended December 31, 2020) (SEC File No. 001-09743).
10.1(o)	- Form of Non-Employee Director Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after May 6, 2019) (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019) (SEC File No. 001-09743).
10.2(a)+	- EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan, dated effective as of April 29, 2021 (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-255691, filed April 30, 2021).
10.2(b)+	- Form of Restricted Stock Award Agreement for EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).
10.2(c)+	- Form of Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).
10.2(d)+	- Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).
10.2(e)+	- Form of Restricted Stock Unit with Performance-Based Conditions ("Performance Unit") Award Agreement for EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).

<u>Exhibit Number</u>	<u>Description</u>
10.2(f)+	- Restricted Stock Unit with Performance-Based Conditions ("Performance Unit") Award Agreement under EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan, by and between EOG and William R. Thomas, effective September 27, 2021 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).
10.2(g)	- Form of Non-Employee Director Restricted Stock Unit Award for EOG Resources, Inc. 2021 Omnibus Equity Compensation Plan (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021) (SEC File No. 001-09743).
10.3(a)+	- EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Plan Document, effective as of December 16, 2008 (Exhibit 10.2(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(b)+	- EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Adoption Agreement, originally dated as of December 16, 2008 (and as amended through February 24, 2012 (including an amendment to Item 7 thereof, effective January 1, 2012, with respect to the deferral of restricted stock units)) (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2011) (originally filed as Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(c)+	- First Amendment to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of January 1, 2013 (Exhibit 10.8 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.3(d)+	- Amendment 2 to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of January 1, 2018 (Exhibit 10.3(d) to EOG's Annual Report on Form 10-K for the year ended December 31, 2018) (SEC File No. 001-09743).
10.3(e)+	- Third Amendment to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of December 17, 2020 (Exhibit 10.2(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2020) (SEC File No. 001-09743).
10.4(a)+	- Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.4(b)+	- First Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of April 30, 2009 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.4(c)+	- Second Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of September 13, 2011 (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 13, 2011) (SEC File No. 001-09743).
10.5(a)+	- Change of Control Agreement by and between EOG and Michael P. Donaldson, effective as of May 3, 2012 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012) (SEC File No. 001-09743).
10.5(b)+	- First Amendment to Change of Control Agreement between EOG and Michael P. Donaldson, effective as of September 4, 2013 (Exhibit 10.7 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.6(a)+	- Change of Control Agreement by and between EOG and Lloyd W. Helms, effective as of June 27, 2013 (Exhibit 10.9 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) (SEC File No. 001-09743).
10.6(b)+	- First Amendment to Change of Control Agreement between EOG and Lloyd W. Helms, Jr., effective as of September 4, 2013 (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.7+	- Change of Control Agreement by and between EOG and Ezra Y. Yacob, effective as of January 26, 2018 (Exhibit 10.10 to EOG's Annual Report on Form 10-K for the year ended December 31, 2017) (SEC File No. 001-09743).
10.8+	- Change of Control Agreement by and between EOG and Kenneth W. Boedeker, effective as of December 19, 2018 (Exhibit 10.11 to EOG's Annual Report on Form 10-K for the year ended December 31, 2018) (SEC File No. 001-09743).

<u>Exhibit Number</u>	<u>Description</u>
10.9+	- Change of Control Agreement by and between EOG and Jeffrey R. Leitzell, effective as of June 17, 2021 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 (SEC File No. 001-09743).
10.10(a)+	- EOG Resources, Inc. Change of Control Severance Plan, as amended and restated effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.10(b)+	- First Amendment to the EOG Resources, Inc. Change of Control Severance Plan, effective as of April 30, 2009 (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.11+	- EOG Resources, Inc. Annual Bonus Plan (effective January 1, 2019) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019) (SEC File No. 001-09743).
10.12+	- EOG Resources, Inc. Employee Stock Purchase Plan (As Amended and Restated Effective January 1, 2018)(Exhibit 4.4(a) to EOG's Registration Statement on Form S-8, SEC File No. 333-224466, filed April 26, 2018).
10.13	- Revolving Credit Agreement, dated as of June 27, 2019, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed July 2, 2019) (SEC File No. 001-09743).
*21	- Subsidiaries of EOG, as of December 31, 2021.
*23.1	- Consent of DeGolyer and MacNaughton.
*23.2	- Consent of Deloitte & Touche LLP.
*24	- Powers of Attorney.
*31.1	- Section 302 Certification of Annual Report of Principal Executive Officer.
*31.2	- Section 302 Certification of Annual Report of Principal Financial Officer.
*32.1	- Section 906 Certification of Annual Report of Principal Executive Officer.
*32.2	- Section 906 Certification of Annual Report of Principal Financial Officer.
*95	- Mine Safety Disclosure Exhibit.
*99.1	- Opinion of DeGolyer and MacNaughton, dated January 27, 2022.
101.INS	- Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
* **101.SCH	- Inline XBRL Schema Document.
* **101.CAL	- Inline XBRL Calculation Linkbase Document.
* **101.DEF	- Inline XBRL Definition Linkbase Document.
* **101.LAB	- Inline XBRL Label Linkbase Document.
* **101.PRE	- Inline XBRL Presentation Linkbase Document.
104	- Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) for Each of the Three Years in the Period Ended December 31, 2021, (ii) the Consolidated Balance Sheets - December 31, 2021 and 2020, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2021, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2021 and (v) the Notes to Consolidated Financial Statements.

+ Management contract, compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: February 24, 2022

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities with EOG Resources, Inc. indicated and on the 24th day of February, 2022.

Signature

Title

/s/ EZRA Y. YACOB

(Ezra Y. Yacob)

Chief Executive Officer and Director
(Principal Executive Officer)

/s/ TIMOTHY K. DRIGGERS

(Timothy K. Driggers)

Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ ANN D. JANSSEN

(Ann D. Janssen)

Senior Vice President and Chief Accounting Officer
(Principal Accounting Officer)

*

Director

(Janet F. Clark)

*

Director

(Charles R. Crisp)

*

Director

(Robert P. Daniels)

*

Director

(James C. Day)

*

Director

(C. Christopher Gaut)

*

Director

(Michael T. Kerr)

*

Director

(Julie J. Robertson)

*

Director

(Donald F. Textor)

*

Chairman of the Board (Director)

(William R. Thomas)

*By:

/s/ MICHAEL P. DONALDSON

(Michael P. Donaldson)

(Attorney-in-fact for persons indicated)