

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

FORM 10-K

- Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2023
or
 Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission file number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

41-0518430

(I.R.S. Employer Identification No.)

1700 Lincoln Street, Suite 3200, Denver, Colorado

(Address of principal executive offices)

80203

(Zip Code)

(303) 861-8140

(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, \$0.01 par value	SM	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 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 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 | <input checked="" type="checkbox"/> | Accelerated filer | <input type="checkbox"/> |
| Non-accelerated filer | <input type="checkbox"/> | Smaller reporting company | <input type="checkbox"/> |
| | | Emerging growth company | <input type="checkbox"/> |

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.

If securities are registered pursuant to section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

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

The aggregate market value of the 116,456,585 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on June 30, 2023, the last business day of the registrant's most recently completed second fiscal quarter, of \$31.63 per share, as reported on the New York Stock Exchange, was \$3,683,521,784. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 8, 2024, the registrant had 115,746,540 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III of this report is incorporated by reference from portions of the registrant's Definitive Proxy Statement on Schedule 14A relating to its 2024 annual meeting of stockholders, to be filed within 120 days after December 31, 2023.

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Cautionary Information about Forward-Looking Statements

This Annual Report on Form 10-K (“Form 10-K” or “this report”) contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (“Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (“Exchange Act”). All statements included in this report, other than statements of historical facts, that address activities, conditions, events, or developments with respect to our financial condition, results of operations, business prospects or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “pending,” “plan,” “potential,” “projected,” “seek,” “target,” “will,” and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear throughout this report, and include statements about such matters as:

- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, plans with respect to future dividend payments, debt redemptions or equity repurchases, capital markets activities, environmental, social, and governance (“ESG”) goals and initiatives, and our outlook on our future financial condition or results of operations;
- the amount and nature of future capital expenditures, the resilience of our assets to declining commodity prices, and the availability of liquidity and capital resources to fund capital expenditures;
- our outlook on prices for future crude oil, natural gas, and natural gas liquids (also referred to throughout this report as “oil,” “gas,” and “NGLs,” respectively), well costs, service costs, production costs, and general and administrative costs, and the effects of inflation on each of these;
- armed conflict, political instability, or civil unrest in oil and gas producing regions and transportation channels, including instability in the Middle East, the wars between Russia and Ukraine and Israel and Hamas, and related potential effects on laws and regulations, or the imposition of economic or trade sanctions;
- any changes to the borrowing base or aggregate lender commitments under our Seventh Amended and Restated Credit Agreement (“Credit Agreement”);
- cash flows, liquidity, interest and related debt service expenses, changes in our effective tax rate, and our ability to repay debt in the future;
- our drilling and completion activities and other exploration and development activities, each of which could be affected by supply chain disruptions and inflation, our ability to obtain permits and governmental approvals, and plans by us, our joint development partners, and/or other third-party operators;
- possible or expected acquisitions and divestitures, including the possible divestiture or farm-out of, or farm-in or joint development of, certain properties;
- oil, gas, and NGL reserve estimates and estimates of both future net revenues and the present value of future net revenues associated with those reserve estimates, as well as the conversion of proved undeveloped reserves to proved developed reserves;
- our expected future production volumes, identified drilling locations, as well as drilling prospects, inventories, projects and programs; and
- other similar matters, such as those discussed in *Management’s Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. We caution you that forward-looking statements are not guarantees of future performance and these statements are subject to known and unknown risks and uncertainties, which may cause our actual results or performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Factors that may cause our financial condition, results of operations, business prospects or economic performance to differ from expectations include the factors discussed in Part I, Item 1A, *Risk Factors* below and elsewhere in this report.

The forward-looking statements in this report speak only as of the filing of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by applicable securities laws.

Glossary

The oil and gas terms and other terms defined in this section are used throughout this report. The definitions of the terms “developed reserves,” “exploratory well,” “field,” “proved reserves,” and “undeveloped reserves” have been abbreviated from the respective definitions under Rule 4-10(a) of Regulation S-X. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the Securities and Exchange Commission’s (“SEC”) website at www.sec.gov.

Ad valorem tax. A tax based on the value of real estate or personal property.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

BBtu. One billion British thermal units.

Bcf. One billion cubic feet, used in reference to gas.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas to one Bbl of oil or NGLs.

Btu. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Completion. The installation of equipment for production of oil, gas, and/or NGLs, or in the case of a dry hole, the reporting to the applicable authority that the well has been abandoned.

Conversion rate. Current year conversions of proved undeveloped reserves to proved developed reserves, divided by beginning of the year proved undeveloped reserves (also commonly referred to in our industry as “*track record*”).

Costs incurred. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed reserves. Reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. An exploratory, development, or extension well that proves to be incapable of producing oil, gas, and/or NGLs in sufficient commercial quantities to justify completion, or upon completion, the economic operation of a well (also referred to as “*non-productive well*”).

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

FASB. Financial Accounting Standards Board.

Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and gas) rights.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

GAAP. Accounting principles generally accepted in the United States.

Gross acres or gross wells. Acres or wells in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses ("LOE"). The expenses incurred in the lifting of oil, gas, and/or NGLs from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet, used in reference to gas.

MMBbl. One million barrels, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet, used in reference to gas.

Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.

NGLs. The combination of ethane, propane, isobutane, normal butane, and natural gasoline that when removed from gas become liquid under various levels of higher pressure and lower temperature.

NYMEX WTI. New York Mercantile Exchange West Texas Intermediate, a common industry benchmark price for oil.

NYMEX Henry Hub ("HH"). New York Mercantile Exchange Henry Hub, a common industry benchmark price for gas.

OPEC+. The Organization of the Petroleum Exporting Countries ("OPEC") plus other non-OPEC oil producing countries.

OPIS. Oil Price Information Service, a common industry benchmark for NGL pricing at Mont Belvieu, Texas.

PV-10. PV-10 is a non-GAAP measure. The present value of estimated future revenue to be generated from the production of estimated proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This measure is presented because management believes it provides useful information to investors for analysis of the Company's fundamental business on a recurring basis.

Productive well. An exploratory, development, or extension well that is producing or is capable of commercial production of oil, gas, and/or NGLs.

Proved reserves. Those quantities of oil, gas, and NGLs 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, and under existing economic conditions, operating methods, and government regulations prior to 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Recompletion. The completion of an existing wellbore in a formation other than that in which the well has previously been completed.

Reserve life index. Expressed in years, represents the estimated proved reserves as of the end of the year divided by actual production for the preceding 12-month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil, gas, and/or associated liquid resources that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resource play. A term used to describe an accumulation of oil, gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has lower expected geological risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from oil, gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and gas property entitling the owner to shares of oil, gas, and NGL production free of costs of exploration, development, and production operations.

Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

SOFR. Secured Overnight Financing Rate.

Standardized measure of discounted future net cash flows. The discounted future net cash flows related to estimated proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, at a 10 percent annual discount rate. The information for this calculation is included in *Supplemental Oil and Gas Information (unaudited)* located in Part II, Item 8 of this report.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and NGLs regardless of whether such acreage contains estimated proved reserves.

Undeveloped reserves. 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 recompletion. The applicable SEC definition of undeveloped reserves provides that undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

PART I

When we use the terms “SM Energy,” the “Company,” “we,” “us,” or “our,” we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business in the *Glossary* section of this report. Throughout this document we make statements and projections that address future expectations, possibilities, or events, all of which may be classified as “forward-looking statements.” Please refer to the *Cautionary Information about Forward-Looking Statements* section of this report for an explanation of these types of statements and the associated risks and uncertainties.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas. SM Energy was founded in 1908, incorporated in Delaware in 1915, and our initial public offering of common stock was in 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol “SM.”

Our principal office is located at 1700 Lincoln Street, Suite 3200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our purpose is to make people’s lives better by responsibly producing energy supplies, contributing to domestic energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets by maintaining and optimizing our high-quality asset portfolio, generating cash flows, and maintaining a strong balance sheet. Our team executes this strategy by prioritizing safety, technological innovation, and stewardship of natural resources, all of which are integral to our corporate culture. Our near-term goals include continuing to return value to stockholders through our Stock Repurchase Program, as defined below, and fixed dividend payments, and by focusing on continued operational excellence.

Our asset portfolio is comprised of high-quality assets in the Midland Basin of West Texas and in the Maverick Basin of South Texas that we believe are capable of generating strong returns in the current macroeconomic environment and provide resilience to commodity price risk and volatility. We seek to maximize returns and increase the value of our top-tier assets through disciplined capital spending, strategic acquisitions, and continued development and optimization of our existing assets. We believe that our high-quality assets facilitate a sustainable approach to prioritizing operational execution, maintaining a strong balance sheet, generating cash flows, returning capital to stockholders, and maintaining financial flexibility.

We are committed to exceptional safety, health, and environmental stewardship; supporting the professional development of a diverse and thriving team of employees; building and maintaining partnerships with our stakeholders by investing in and connecting with the communities where we live and work; and transparency in reporting our progress in these areas. We have prioritized ESG initiatives by, among other things, integrating enhanced environmental and social programs throughout the organization and setting goals that include safety and spill metrics, minimizing flaring and reducing greenhouse gas (“GHG” or “GHGs”) emissions intensity, and maintaining low methane emissions intensity. Additionally, we are implementing systems and technologies to track ESG metrics to improve future reporting and performance and to increase employee awareness. The Environmental, Social and Governance Committee of our Board of Directors oversees, among other things, the effectiveness of our ESG policies, programs and initiatives, monitors and responds to emerging issues, and, together with management, reports to our Board of Directors regarding such matters. Further demonstrating our commitment to sustainable operations and environmental stewardship, compensation for our executives and eligible employees under our long-term incentive plan, and compensation for all employees under our short-term incentive plan is calculated based on, in part, certain Company-wide, performance-based metrics that include key financial, operational, environmental, health, and safety measures.

Significant Developments in 2023

Return of Capital Program. In 2023, we continued to execute on our goal of sustainably returning capital to our stockholders through our Stock Repurchase Program and fixed quarterly dividend payments. Our Stock Repurchase Program commenced in September 2022, and originally authorized the repurchase of up to \$500.0 million in aggregate value of our common stock through December 31, 2024 (“Stock Repurchase Program”). During the year ended December 31, 2023, we repurchased and subsequently retired 6.9 million shares of our common stock at a cost of \$228.0 million, excluding excise taxes, commissions, and fees. As of the filing of this report, \$214.9 million remains available for repurchases of our outstanding common stock under the Stock Repurchase Program. During the year ended December 31, 2023, we paid dividends of \$0.60 per share, an increase from \$0.16 per share paid during the year ended December 31, 2022. Additionally, in November 2023, we announced a 20 percent increase to our fixed dividend to \$0.72 per share annually, to be paid in quarterly increments of \$0.18 per share, beginning in the first quarter of 2024. Please refer to *Note 3 – Equity* in Part II, Item 8 of this report for additional discussion.

Acquisition Activity. During 2023, we acquired approximately 20,000 net acres of oil and gas properties in Dawson and northern Martin counties, Texas. Additionally, in the Midland Basin, we added approximately 9,100 net acres through organic leasing activity, we completed an asset exchange, and we acquired additional working interests in certain wells. Please refer to *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion.

Reserves and Capital Investment. Our total estimated net proved reserves were 604.9 MMBOE as of December 31, 2023, which was an increase of 13 percent from 537.4 MMBOE as of December 31, 2022. This increase primarily consisted of revisions of previous estimates of 113.9 MMBOE related to infill reserves in both our South Texas and Midland Basin programs, partially offset by 55.5 MMBOE of production during 2023. Our proved reserve life index increased to 10.9 years as of December 31, 2023, compared with 10.1 years as of December 31, 2022. Please refer to *Areas of Operation* and *Reserves* below for additional discussion regarding revisions of previous estimates due to infill, price, and performance revisions, the removal of certain proved undeveloped reserve cases that are no longer within our development plan over the next five years, and additions from extensions and discoveries. Costs incurred increased 28 percent from 2022 to \$1.2 billion in 2023. Please refer to *Areas of Operation* below, and to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Production, Pricing and Revenue, and Commodity Derivatives. Our average net daily equivalent production in 2023 increased five percent compared with 2022 to 152.0 MBOE, consisting of 65.1 MBbl of oil, 362.7 MMcf of gas, and 26.4 MBbl of NGLs, as a result of an increased number of completions. Oil production as a percentage of total production decreased to 43 percent in 2023 from 45 percent in 2022, as a result of production from our South Texas assets becoming a higher percentage of total production in 2023.

Realized prices before the effect of net derivative settlements (“realized price” or “realized prices”) for oil, gas, and NGLs decreased 19 percent, 61 percent, and 35 percent, respectively, for the year ended December 31, 2023, compared with 2022. As a result of decreased realized prices, oil, gas, and NGL production revenue decreased 29 percent to \$2.4 billion for the year ended December 31, 2023, compared with \$3.3 billion for 2022. Oil production revenue was 77 percent and 68 percent of total production revenue for the years ended December 31, 2023, and 2022, respectively.

We recorded a net derivative gain of \$68.2 million for the year ended December 31, 2023, compared to a net derivative loss of \$374.0 million for the year ended December 31, 2022. These amounts include a net derivative settlement gain of \$26.9 million for the year ended December 31, 2023, and a net derivative settlement loss of \$710.7 million for the year ended December 31, 2022.

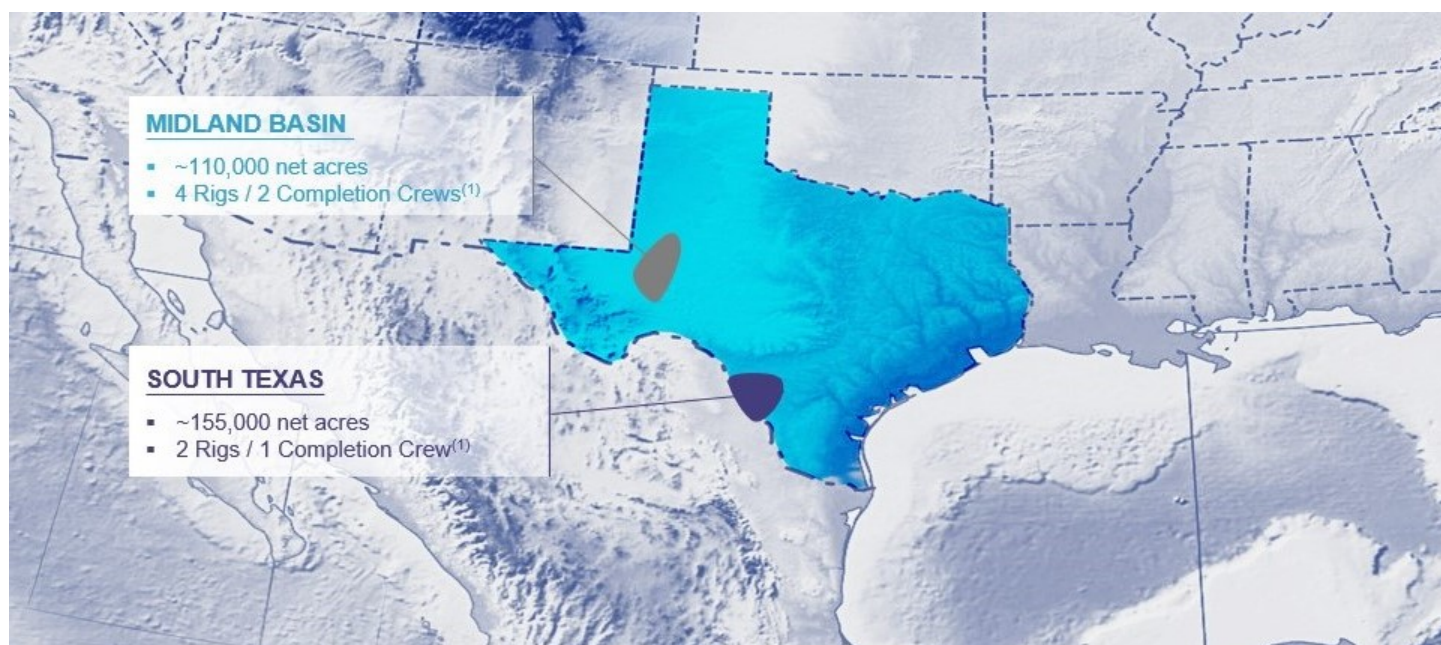
Please refer to *Areas of Operation* below and *Overview of the Company* in Part II, Item 7 of this report for additional discussion.

Outlook

Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets. We are focused on operational execution, maintaining and expanding our portfolio quality and depth, and returning capital to stockholders through our Stock Repurchase Program and fixed dividend, while maintaining a strong balance sheet.

We expect our total 2024 capital program to be between \$1.16 billion and \$1.20 billion, excluding acquisitions, which we expect to fund with cash flows from operations and cash on hand. We plan to focus our 2024 capital program on highly economic oil development projects in both our Midland Basin and South Texas assets, including the assets we acquired during 2023. We expect to repurchase additional shares of our outstanding common stock through our Stock Repurchase Program during 2024, under which \$214.9 million remains available for repurchases through December 31, 2024, as of the filing of this report.

Areas of Operation



⁽¹⁾ As of December 31, 2023.

Our 2023 operations were concentrated in the Midland Basin and South Texas, as described below. The following table summarizes estimated net proved reserves, net production volumes, and costs incurred for the year ended December 31, 2023, for these areas:

	Midland Basin	South Texas	Total ⁽¹⁾
Net proved reserves			
Oil (MMBbl)	159.2	70.9	230.1
Gas (Bcf)	654.8	877.2	1,532.0
NGLs (MMBbl)	0.2	119.3	119.5
MMBOE ⁽¹⁾	268.5	336.4	604.9
Relative percentage	44 %	56 %	100 %
Proved developed %	62 %	52 %	56 %
Net production volumes			
Oil (MMBbl)	17.5	6.3	23.8
Gas (Bcf)	59.8	72.6	132.4
NGLs (MMBbl)	—	9.6	9.7
MMBOE ⁽¹⁾	27.5	28.0	55.5
Avg. daily equivalents (MBOE/d) ⁽¹⁾	75.4	76.7	152.0
Relative percentage	50 %	50 %	100 %
Costs incurred (in millions) ⁽²⁾	\$ 768.1	\$ 423.5	\$ 1,235.0

⁽¹⁾ Amounts may not calculate due to rounding.

⁽²⁾ Asset costs incurred do not sum to total costs incurred primarily due to corporate charges incurred on exploration activities and costs related to exploration efforts outside of our core areas of operation that are excluded from this table. For total costs incurred, please refer to *Costs Incurred in Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Total estimated net proved reserves at December 31, 2023, increased 13 percent from December 31, 2022. Total net equivalent production increased five percent for the year ended December 31, 2023, compared with 2022. Costs incurred for the year ended December 31, 2023, increased 28 percent compared with 2022, primarily as a result of increases in capital activity related to the development of both our Midland Basin and South Texas assets, acquisitions of proved and unproved properties and leasing activity in the Midland Basin, and inflation.

Midland Basin. Our Midland Basin assets, located in the Permian Basin in West Texas, are comprised of approximately 110,000 net acres, and include our RockStar assets in Howard and Martin counties, our Sweetie Peck assets in Upton and Midland counties, and our Klondike assets, which we acquired in 2023, in Dawson and northern Martin counties (“Midland Basin”). In 2023, drilling and completion activities were focused within our RockStar and Sweetie Peck assets, and we began drilling on our newly acquired Klondike acreage. Our current Midland Basin position provides substantial future development opportunities within multiple oil-rich intervals, including the Spraberry and Wolfcamp formations. We expect our 2024 capital activity in the Midland Basin to be focused on highly economic oil development projects.

In 2023, costs incurred were \$768.1 million, and we averaged three drilling rigs and one completion crew. We drilled 54 gross (37 net) wells, completed 64 gross (54 net) wells, and acquired additional working interests in five net wells during the year ended December 31, 2023. As of December 31, 2023, 39 gross (29 net) wells had been drilled but not completed in our operated Midland Basin program. Net equivalent production for the year ended December 31, 2023, was 27.5 MMBOE, a seven percent decrease from 29.7 MMBOE for the year ended December 31, 2022. Estimated net proved reserves increased four percent to 268.5 MMBOE at December 31, 2023, from 257.4 MMBOE at December 31, 2022. Positive revisions of previous estimates primarily consisted of 43.4 MMBOE of infill and 21.3 MMBOE resulting from changes to decline curve estimates based on reservoir engineering analysis, partially offset by negative revisions of 18.2 MMBOE related to well performance and production of 27.5 MMBOE.

South Texas. Our South Texas assets are comprised of approximately 155,000 net acres located in Dimmit and Webb counties, Texas (“South Texas”). In 2023, our operations in South Texas were focused on production from the Austin Chalk formation and the Eagle Ford shale formation, and further development of the Austin Chalk formation. Our overlapping acreage position in the Maverick Basin in South Texas covers a significant portion of the western Eagle Ford shale and Austin Chalk formations (“Maverick Basin”) and includes acreage across the oil, gas-condensate, and dry gas windows with gas composition amenable to processing for NGL extraction. We expect our 2024 capital activity in South Texas to be focused primarily on developing the Austin Chalk formation.

In 2023, costs incurred were \$423.5 million, and we averaged two drilling rigs and one completion crew. We drilled 46 gross (46 net) wells and completed 38 gross (37 net) wells, and as of December 31, 2023, 37 gross (37 net) wells had been drilled but not completed in our operated South Texas program. Net equivalent production for the year ended December 31, 2023, was 28.0 MMBOE, a 20 percent increase from 23.2 MMBOE for the year ended December 31, 2022. Estimated net proved reserves increased 20 percent to 336.4 MMBOE at December 31, 2023, from 280.0 MMBOE at December 31, 2022. Positive revisions of previous estimates consisted of 70.4 MMBOE of infill and 44.0 MMBOE of performance revisions resulting from changes to decline curve estimates based on reservoir engineering analysis. Additions of 30.1 MMBOE were the result of continued success in our development of the Austin Chalk formation. These increases were partially offset by production of 28.0 MMBOE, negative price revisions of 24.5 MMBOE, and negative revisions of 9.9 MMBOE related to well performance. As a result of revising our development plan, partially in response to decreased benchmark gas prices and certain lease obligations, we removed 25.8 MMBOE of net proved undeveloped reserves that were no longer in our five-year development plan. These net proved undeveloped reserves primarily related to our Eagle Ford assets and were replaced with certain infill revisions to net proved undeveloped reserves associated with different locations that were added to our five-year development plan. Additionally, infill revisions replaced converted net proved undeveloped reserves.

Office Space. As of December 31, 2023, we leased and owned office space as summarized in the table below:

	Approximate Square Footage Leased	Approximate Square Footage Owned
Corporate - Denver, CO	59,000	—
Midland, TX	59,000	—
Houston, TX and Catarina, TX, respectively	21,000	12,000
Total	139,000	12,000

Reserves

Reserve estimates are inherently imprecise. Estimates for new discoveries and undeveloped locations are considered more imprecise than reserve estimates for producing oil and gas properties. Accordingly, we expect these estimates to change as new information becomes available. The table below presents the standardized measure of discounted future net cash flows and PV-10. PV-10 is a non-GAAP financial measure that is reconciled to the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure. PV-10 does not include the effects of income taxes on future net revenues. Neither the standardized measure of discounted future net cash flows nor PV-10 represents the fair market value of our oil and gas properties. We and others in the oil and gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held before consideration of tax characteristics specific to individual entities. Please refer to the *Glossary* section of this report for additional information regarding these measures and refer to the reconciliation of the standardized measure of discounted future net cash flows to PV-10 set forth below. The actual quantities and present value of our estimated net proved reserves may be more or less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year. The table below should be read along with *Risk Factors* in Part I, Item 1A of this report.

The following table summarizes estimated net proved reserves, the standardized measure of discounted future net cash flows (GAAP), PV-10 (non-GAAP), the prices used in the calculation of net proved reserves estimates, and reserve life index as of December 31, 2023, 2022, and 2021:

	As of December 31,		
	2023	2022	2021
Net reserve volumes:			
Proved developed			
Oil (MMBbl)	118.5	110.4	110.7
Gas (Bcf)	948.5	902.1	833.0
NGLs (MMBbl)	64.7	57.1	50.7
MMBOE ⁽¹⁾	341.2	317.8	300.2
Proved undeveloped			
Oil (MMBbl)	111.6	95.4	88.8
Gas (Bcf)	583.5	500.8	410.4
NGLs (MMBbl)	54.8	40.7	34.5
MMBOE ⁽¹⁾	263.6	219.6	191.8
Total proved ⁽¹⁾			
Oil (MMBbl)	230.1	205.8	199.5
Gas (Bcf)	1,532.0	1,402.9	1,243.5
NGLs (MMBbl)	119.5	97.8	85.2
MMBOE	604.9	537.4	492.0
Net proved developed reserves percentage	56 %	59 %	61 %
Net proved undeveloped reserves percentage	44 %	41 %	39 %
Reserve data (in millions):			
Standardized measure of discounted future net cash flows (GAAP)	\$ 6,280.1	\$ 9,962.1	\$ 6,962.6
PV-10 (non-GAAP):			
Proved developed PV-10	\$ 4,965.1	\$ 8,234.8	\$ 5,407.2
Proved undeveloped PV-10	2,411.4	3,919.7	2,751.4
Total proved PV-10 (non-GAAP)	\$ 7,376.5	\$ 12,154.5	\$ 8,158.6
12-month trailing average prices: ⁽²⁾			
Oil (per Bbl)	\$ 78.22	\$ 93.67	\$ 66.56
Gas (per MMBtu)	\$ 2.64	\$ 6.36	\$ 3.60
NGLs (per Bbl)	\$ 27.72	\$ 42.52	\$ 36.60
Reserve life index (years) ⁽³⁾			
	10.9	10.1	9.6

⁽¹⁾ Amounts may not calculate due to rounding.

⁽²⁾ The prices used in the calculation of proved reserve estimates reflect the unweighted arithmetic average of the first-day-of-the-month price of each month within the trailing 12-month period in accordance with SEC rules. We then adjust these prices to reflect appropriate quality and location differentials over the period in estimating our net proved reserves.

⁽³⁾ Please refer to the reserve life index term in the *Glossary* section of this report for information describing how this metric is calculated.

The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 (non-GAAP) of total estimated net proved reserves. Please refer to the *Glossary* section of this report for the definitions of standardized measure of discounted future net cash flows and PV-10.

	As of December 31,		
	2023	2022	2021
	(in millions)		
Standardized measure of discounted future net cash flows (GAAP)	\$ 6,280.1	\$ 9,962.1	\$ 6,962.6
Add: 10 percent annual discount, net of income taxes	5,294.5	7,551.5	4,844.9
Add: future undiscounted income taxes	2,000.0	3,888.3	2,130.3
Pre-tax undiscounted future net cash flows	13,574.6	21,401.9	13,937.8
Less: 10 percent annual discount without tax effect	(6,198.1)	(9,247.4)	(5,779.2)
PV-10 (non-GAAP)	<u>\$ 7,376.5</u>	<u>\$ 12,154.5</u>	<u>\$ 8,158.6</u>

Proved Undeveloped Reserves

Proved undeveloped reserves include those reserves that are expected to be recovered from future wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of economic producibility when drilled or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. As of December 31, 2023, we did not have any net proved undeveloped reserves that had been on our books in excess of five years, and substantially all of our net proved undeveloped reserves were on acreage that was not expected to expire, or that was expected to be held through renewal, before the targeted completion date.

For proved undeveloped locations that are more than one development spacing area from developed producing locations, we utilized reliable geologic and engineering technology when booking estimated net proved undeveloped reserves. Of the 263.6 MMBOE of total net proved undeveloped reserves as of December 31, 2023, approximately 36.8 MMBOE of net proved undeveloped reserves in the Midland Basin and 87.3 MMBOE of net proved undeveloped reserves in South Texas were offset by more than one development spacing area from the nearest proved developed producing location. We incorporated public and proprietary data from multiple sources to establish geologic continuity of each formation and their producing properties. This included seismic data and interpretations (3-D and micro seismic), open hole log information (both vertically and horizontally collected) and petrophysical analysis of that log data, mud logs, gas sample analysis, measurements of total organic content, thermal maturity, test production, fluid properties, and core data as well as statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas where both established geologic consistency and sufficient statistical performance data could be demonstrated to provide reasonably certain results.

As of December 31, 2023, estimated net proved undeveloped reserves increased 44.1 MMBOE, or 20 percent, compared with December 31, 2022. The following table provides a reconciliation of our net proved undeveloped reserves for the year ended December 31, 2023:

	Total (MMBOE)
Total net proved undeveloped reserves:	
Beginning of year	219.6
Revisions of previous estimates	98.8
Conversions to proved developed	(43.1)
Removed for five-year rule	(30.8)
Additions from extensions and discoveries	22.7
Sales of reserves	(5.3)
Purchases of minerals in place	1.8
End of year ⁽¹⁾	<u>263.6</u>

⁽¹⁾ Amount may not calculate due to rounding.

Revisions of previous estimates. During 2023, revisions of previous estimates totaled 98.8 MMBOE. Positive revisions consisted of 103.8 MMBOE of infill reserves, of which 60.5 MMBOE and 43.3 MMBOE of estimated net proved undeveloped reserves

were attributable to our South Texas and Midland Basin programs, respectively, and 13.3 MMBOE of performance revisions resulted from changes to decline curve estimates based on reservoir engineering analysis. Negative revisions consisted of 14.2 MMBOE that resulted from well performance related to infill development, and price revisions of 4.0 MMBOE that resulted primarily from decreases in benchmark gas and NGL prices.

Conversions to proved developed. Our 2023 conversion rate was 20 percent and primarily resulted from the development of proved reserves in our Midland Basin program and in our Austin Chalk assets in our South Texas program. During 2023, we incurred \$740.2 million on projects with reserves booked as proved undeveloped at the end of 2022, of which \$515.9 million was spent on converting net proved undeveloped reserves to proved developed reserves by December 31, 2023. At December 31, 2023, drilled but not completed wells represented 41.2 MMBOE of total estimated net proved undeveloped reserves. We expect to incur \$212.6 million of additional capital expenditures in completing these drilled but not completed wells, and we expect all estimated net proved undeveloped reserves to be converted to proved developed reserves within five years from their initial booking as net proved undeveloped reserves.

Removed for five-year rule. As a result of our testing and delineation efforts in 2023, we revised certain aspects of our future development plan to focus on maximizing returns and the value of our assets. We removed 30.8 MMBOE of estimated net proved undeveloped reserves and reclassified these locations to unproved reserve categories based on development schedule revisions made partially in response to decreased benchmark gas prices and certain lease obligations. Of the 30.8 MMBOE, 25.8 MMBOE primarily related to our Eagle Ford assets in our South Texas program, and 5.0 MMBOE related to our Midland Basin program.

Additions from extensions and discoveries. During 2023, we added 22.7 MMBOE of estimated net proved undeveloped reserves, of which 21.9 MMBOE were in South Texas, and resulted from extensions from our continued success in delineating the Austin Chalk formation.

As of December 31, 2023, estimated future development costs relating to our net proved undeveloped reserves totaled \$2.8 billion, and we expect to incur approximately \$860.6 million, \$585.6 million, and \$555.7 million in 2024, 2025, and 2026, respectively.

Internal Controls Over Proved Reserves Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC's regulations. Our process for managing and monitoring our proved reserves is delegated to our corporate reserves group and is coordinated by our Corporate Engineering Manager, subject to the oversight of our management and the Audit Committee of our Board of Directors ("Audit Committee"), as discussed below. Our Corporate Engineering Manager has worked in the energy industry since 2008 and has been employed by the Company since 2010. He holds a Bachelor of Science degree in Petroleum Engineering from Montana Technological University and is a Registered Professional Petroleum Engineer in the states of Texas, Wyoming, and Montana. He is also a member of the Society of Petroleum Engineers. Technical, geological, and engineering reviews of our assets are performed throughout the year by our staff. Data obtained from these reviews, in conjunction with economic data and our ownership information, is used in making a determination of estimated proved reserve quantities. Our asset teams' engineering technical staff do not report directly to our Corporate Engineering Manager; they report to either their respective asset technical managers or directly to the Senior Vice President of Exploration, Development and EHS. This design is intended to promote objective and independent analysis within our asset teams in the proved reserves estimation process.

Third-party Reserves Audit

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world since 1937. Ryder Scott performed an independent audit using its own engineering assumptions, but with economic and ownership data we provided. Ryder Scott audits a minimum of 80 percent of our total calculated proved reserve PV-10. In the aggregate, the proved reserve amounts of our audited properties determined by Ryder Scott are required, per our policy, to be within 10 percent of our proved reserve amounts for the total Company, as well as for each respective major asset. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is a Senior Vice President who received a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002. She is a registered Professional Engineer in the State of Texas and a member of the Society of Petroleum Engineers. The 2023 Ryder Scott audit report is included as Exhibit 99.1.

In addition to a third-party audit, our reserves are reviewed by our management with the Audit Committee. Our management, which includes our President and Chief Executive Officer, Executive Vice President and Chief Financial Officer, and Senior Vice President of Exploration, Development and EHS, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews a summary of the final reserves estimate in conjunction with Ryder Scott's results and also meets with Ryder Scott representatives, separate from our management, from time to time to discuss processes and findings.

Production

The following table summarizes our net production volumes and realized prices for oil, gas, and NGLs produced and sold during the periods presented, and related production expense on a per BOE basis:

	For the Years Ended December 31,		
	2023	2022	2021
Net production volumes			
Oil (MMBbl)	23.8	24.0	27.9
Gas (Bcf)	132.4	125.9	108.4
NGLs (MMBbl)	9.7	8.0	5.4
Equivalent (MMBOE) ⁽¹⁾	55.5	53.0	51.4
Midland Basin net production volumes ⁽²⁾			
Oil (MMBbl)	17.5	19.1	25.2
Gas (Bcf)	59.8	63.5	55.4
NGLs (MMBbl)	—	—	—
Equivalent (MMBOE) ⁽¹⁾	27.5	29.7	34.4
Maverick Basin net production volumes ⁽²⁾			
Oil (MMBbl)	6.2	4.8	2.7
Gas (Bcf)	72.5	62.4	52.8
NGLs (MMBbl)	9.6	8.0	5.4
Equivalent (MMBOE) ⁽¹⁾	27.9	23.2	16.9
Realized price			
Oil (per Bbl)	\$ 76.28	\$ 94.67	\$ 67.72
Gas (per Mcf)	\$ 2.48	\$ 6.28	\$ 4.85
NGLs (per Bbl)	\$ 23.02	\$ 35.66	\$ 33.67
Per BOE	\$ 42.60	\$ 63.18	\$ 50.58
Production expense per BOE			
Lease operating expense	\$ 5.13	\$ 5.03	\$ 4.39
Transportation costs	\$ 2.46	\$ 2.83	\$ 2.71
Production taxes	\$ 1.89	\$ 3.07	\$ 2.36
Ad valorem tax expense	\$ 0.67	\$ 0.79	\$ 0.38

⁽¹⁾ Amounts may not calculate due to rounding.

⁽²⁾ For each of the years ended December 31, 2023, 2022, and 2021, total estimated net proved reserves attributed to our Midland Basin field and our Maverick Basin field each exceeded 15 percent of our total estimated net proved reserves expressed on an equivalent basis.

Productive Wells

As of December 31, 2023, we had working interests in 898 gross (795 net) productive oil wells and 528 gross (494 net) productive gas wells. Productive wells are wells producing in commercial quantities or wells capable of commercial production that are temporarily shut-in. Multiple completions in the same wellbore are counted as one well, and as of December 31, 2023, two of these wells had multiple completions. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil when it first commenced production, but such designation may not be indicative of current or future production composition.

Drilling and Completion Activity

All of our drilling and completion activities are conducted by independent contractors using equipment they own and operate. The following table summarizes the number of operated and outside-operated wells drilled and completed or recompleted on our properties in 2023, 2022, and 2021, excluding non-consented projects, active injector wells, saltwater disposal wells, or wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	74	62	68	57	107	91
Gas	21	21	18	18	11	8
Non-productive	—	—	—	—	—	—
	95	83	86	75	118	99
Exploratory wells						
Oil	5	4	4	3	2	2
Gas	5	5	2	2	8	8
Non-productive ⁽¹⁾	1	1	1	1	—	—
	11	10	7	6	10	10
Total	106	93	93	81	128	109

Note: The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated.

⁽¹⁾ For the year ended December 31, 2023, one gross (one net) well was unsuccessful due to technical issues during the drilling phase and was not included in the drilled or completed well counts.

In addition to the wells completed in 2023 (included in the table above), we were actively participating in the drilling of seven gross (seven net) wells and had 81 gross (70 net) drilled but not completed wells as of January 31, 2024. Drilled but not completed wells as of January 31, 2024, represent wells that were being completed or were waiting on completion. The drilled but not completed well count as of January 31, 2024, includes nine gross (nine net) wells that were not included in our five-year development plan as of December 31, 2023, eight of which are in the Eagle Ford shale.

Title to Properties

As of December 31, 2023, over 97 percent of our operated oil and gas producing assets are located on private lands, are held pursuant to oil and gas leases from private mineral owners, and are not located on federal lands or leased from the federal government. The remainder of our operated oil and gas producing assets are located on Texas state lands. We have obtained title opinions or have conducted other title review on substantially all of our producing properties and believe we have satisfactory title to such properties. We obtain new or updated title opinions prior to commencing initial drilling operations on the properties that we operate. Most of our producing properties are subject to mortgages securing indebtedness under our Credit Agreement, as defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report, royalty and overriding royalty interests, liens for current taxes, and other ordinary course burdens that we believe do not materially interfere with the development of such properties. We typically perform title investigations in accordance with standards generally accepted in the oil and gas industry before acquiring developed and undeveloped leasehold acreage.

Acreage

The following table sets forth the number of gross and net surface acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes that we held as of December 31, 2023:

	Developed Acres ⁽¹⁾		Undeveloped Acres ⁽²⁾⁽³⁾		Total	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin:						
RockStar	69,938	63,204	384	368	70,322	63,572
Sweetie Peck	19,905	16,854	13,513	9,038	33,418	25,892
Klondike	6,619	5,687	18,107	15,008	24,726	20,695
Midland Basin Total ⁽⁴⁾	96,462	85,745	32,004	24,414	128,466	110,159
South Texas	89,703	89,107	68,470	65,730	158,173	154,837
Other ⁽⁵⁾	10,499	10,499	90,078	25,606	100,577	36,105
Total	196,664	185,351	190,552	115,750	387,216	301,101

⁽¹⁾ Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations but has been included only as developed acreage in the table above.

⁽²⁾ Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

⁽³⁾ As of February 8, 2024, 2,077, 7,946, and 12,131 net acres of our undeveloped acreage is scheduled to expire by December 31, 2024, 2025, and 2026, respectively, unless production is established or we take other action to extend the terms of the applicable leases. Certain of our acreage, primarily in South Texas, is subject to lease consolidation agreements containing drilling, completion, and other obligations that we currently intend to satisfy. Failure to meet these obligations results in payments to lessors, or termination of the lease consolidation agreements, which could result in additional future lease expirations if continuous development obligations required by individual leases are not met.

⁽⁴⁾ As of December 31, 2023, total Midland Basin acreage excludes 1,213 net acres associated with drill-to-earn opportunities that we intend to pursue.

⁽⁵⁾ Includes other non-core acreage located in Colorado, Louisiana, Montana, North Dakota, Texas, Utah, and Wyoming.

Delivery Commitments

For gathering, processing, transportation throughput, and delivery commitments, please refer to *Delivery Commitments* within *Note 6 – Commitments and Contingencies* in Part II, Item 8 of this report.

Major Customers

For major customers and entities under common control that accounted for 10 percent or more of our total oil, gas, and NGL production revenue for at least one of the years ended December 31, 2023, 2022, and 2021, please refer to *Concentration of Credit Risk and Major Customers* within *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report.

Human Capital

Our Company culture recognizes our employees as our most valuable assets, encourages personal and professional development, promotes innovation and leadership among all employees and, in turn, supports our efforts to attract and retain talent. Through our culture, we promote:

- integrity and ethical behavior in the conduct of our business;
- environmental, health, and safety priorities;
- prioritizing the success of others and the team;
- collaboration and openness to new ideas and technologies that serve business improvement;
- support for team members' professional and personal development; and
- support for the communities where we live and work.

The core values of integrity and ethical behavior are the pillars of our culture, and all employees are responsible for upholding Company-wide standards and values. We have policies designed to promote ethical conduct and integrity, which employees are

required to read and acknowledge on an annual basis. The health and safety of our employees and contractors is our highest priority. We strive to achieve performance excellence in environmental, health, and safety management, and compensation of all employees is tied to annual environmental, health, and safety performance goals.

Personal and professional development is an important part of our culture and is employee driven, manager facilitated, and organizationally supported. Employees are routinely provided training opportunities to develop skills in leadership, safety, and technical acumen, which help strengthen our efforts to conduct business with high ethical standards. During 2023, many of our employees participated in two leadership and talent development programs that included more than 4,300 hours of aggregate training, exclusive of safety and other specialized technical training.

We measure employee engagement and satisfaction through periodic surveys, administered by an independent third-party vendor.

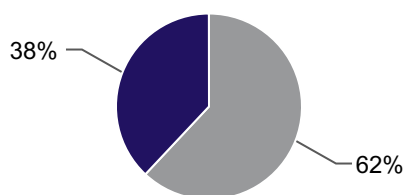
We are proud of our many outstanding employees who invest their time, talents, and financial resources in their communities. Our annual charitable giving program includes a monetary match of our employees' personal contributions to qualified organizations and up to 12 hours per employee of Company-granted time to volunteer in the communities where we live and work.

We strive to provide competitive, performance-based compensation and benefits to our employees, including market-competitive pay, short-term and long-term incentive compensation plans, an employee stock purchase program, and various healthcare, retirement, and other benefit packages such as a hybrid work environment that is guided by each employee's job function and responsibilities. Compensation for our executives and employees under our short-term and long-term incentive plans is determined based on individual performance and Company performance with respect to qualitative and quantitative metrics that include environmental, health, and safety measures. The Compensation Committee of our Board of Directors oversees our compensation programs and regularly modifies program design to incentivize achievement of our corporate strategy and the matters of importance to our stakeholders. Significant planning for succession of key personnel is performed each year, or more frequently as deemed necessary by management.

As of February 8, 2024, we had 544 full-time employees, none of whom were subject to a collective bargaining agreement. We are committed to diversity at all levels of our organization, and we strive to provide equal employment opportunities to all employees and job applicants. We regularly perform internal analyses of our workforce demographics and, at times, we retain a third party to conduct discrimination and pay equity testing. No discriminatory practices have been identified and no evidence of discrimination or pay inequity has been found. Additionally, we have established procedures and controls designed to support our objective of remaining, at all times, in material compliance with applicable federal, state, and local laws and governmental regulations.

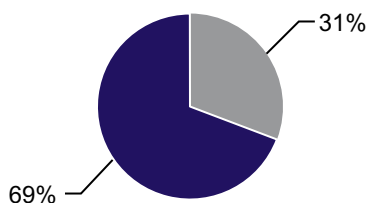
The following charts present certain Board of Directors and workforce metrics as of February 8, 2024:

Board of Directors Diversity



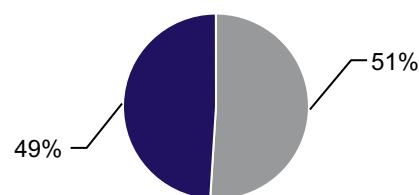
■ Ethnically Diverse or Female
■ Ethnically Non-Diverse Male

Officer Diversity ⁽¹⁾



■ Ethnically Diverse or Female
■ Ethnically Non-Diverse Male

Employee Diversity



■ Ethnically Diverse or Female
■ Ethnically Non-Diverse Male

Note: Ethnic diversity data is determined under guidelines set forth by the United States Equal Employment Opportunity Commission and includes the following categories: American Indian or Alaska Native, Asian, Black or African American, Hispanic or Latino, or the combination of two or more races (not Hispanic or Latino).

⁽¹⁾ Includes officers at the level of Vice President and above.

Seasonality

The price of crude oil is primarily driven by global socioeconomic and geopolitical factors and is less affected by seasonal fluctuations; however, demand for energy is generally higher in the winter and in the summer driving season. The demand and price for gas generally increases during winter months and decreases during summer months. To lessen the effect of seasonal gas demand and price fluctuations, pipelines, utilities, local distribution companies, and industrial users regularly utilize gas storage facilities and forward

purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can divert gas that is traditionally placed into storage which, in turn, may increase the typical winter seasonal price. Seasonal anomalies, such as mild or extreme winters sometimes lessen or exacerbate these fluctuations.

Certain of our drilling, completion, and other operational activities are also subject to seasonal limitations. Seasonal weather conditions, government regulations, and lease stipulations could adversely affect our ability to conduct drilling activities in some of the areas where we operate. Please refer to *Risk Factors* in Part I, Item 1A of this report for additional discussion.

Competition

The oil and gas industry is highly competitive, particularly with respect to acquiring prospective oil and gas properties. We believe our acreage positions provide a foundation for development activities that we expect to fuel our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from many major and independent oil and gas companies, which in some cases have larger technical teams and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and gas reserves, but also have gathering, processing or refining operations, market refined products, provide, dispose of and transport fresh and produced water, own drilling rigs or production equipment, or generate electricity, all of which, individually or in the aggregate, could provide such companies with a competitive advantage.

We also compete with other oil and gas companies in securing drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells, as well as for the gathering, transporting, and processing of oil, gas, NGLs, and water. Consequently, we may face shortages, delays, or increased costs in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including renewable energy sources such as solar and wind-generated energy, and other fossil fuels such as coal. Competitive conditions may be affected by future energy, environmental, climate-related, financial, or other policies, legislation, and regulations.

In addition, we compete for professionals in our workforce, including specialized roles in the oil and gas industry such as geologists, geophysicists, engineers, and others. Throughout the general labor market, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to the evolving demographics of our industry. The oil and gas industry is not insulated from the competition for quality people, and we must compete effectively to be successful. Please refer to *Human Capital* above and *Risk Factors* in Part I, Item 1A of this report for additional discussion.

Government Regulations

Although our regulatory compliance obligations are mitigated by the fact that we do not own or operate oil and gas properties on federal lands, nearly every aspect of our business is subject to expansive federal, state, and local laws and governmental regulations. These laws and regulations frequently change in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential to increase our cost of conducting business and consequently could affect our profitability.

Energy Regulations

Texas, the state where we conduct operations and lease or own nearly all of our oil and gas assets, has adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations requiring permits for the drilling of wells, imposing bond requirements in order to drill or operate wells, governing the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to Texas conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, Texas conservation laws establish maximum rates of production from oil and gas wells, generally limit or prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratable or fair apportionment of production from fields and individual wells.

Our sales of gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for gas production.

Environmental, Health, and Safety Matters

General. Our operations are subject to stringent and complex federal, state, and local laws and regulations governing protection of the environment and worker health and safety, as well as the discharge of materials and emissions into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities, and concentration of various substances and emissions that may be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as closing pits and plugging abandoned wells.

These laws, rules, and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of conducting business and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes may result in more stringent, or different permitting, waste handling, disposal, and cleanup requirements for the oil and gas industry and could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules, and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency (“EPA”), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water, and most of the other wastes associated with the exploration, development, and production of oil or gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation, and Liability Act. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release or threatened release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of, or transported, a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of environmental investigation and certain health studies. In addition, it is not uncommon for third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and gas exploration and production for many years. CERCLA excludes petroleum and natural gas from its definition of hazardous substances, and although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances or wastes may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third-parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties, and the substances disposed or released on them, may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, pay fines, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (“Clean Water Act”) and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, or analogous state agencies. This includes the discharge of certain storm water without a permit which requires periodic monitoring and sampling. In addition, the Clean Water Act regulates wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process and discharged to publicly-owned wastewater treatment facilities. The Clean Water Act also prohibits discharge of dredged or fill material into waters of the United States, including wetlands, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers, or a state, if the state has assumed authority to issue such permits. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 (“OPA”) addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act (“CAA”) and comparable state laws and regulations regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements, such as requirements for emission reduction, capture and control. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of hazardous air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. Please refer to the *Environmental* section in Part II, Item 7 of this report for additional information about the regulation of air emissions from the oil and gas sector.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other GHGs endanger public health and welfare, and as a result, began adopting and implementing a comprehensive suite of regulations to restrict emissions of GHGs under existing provisions of the CAA. While President Trump’s administration took steps to rescind or review many of these regulations, President Biden’s administration has actively been reviewing those actions and taking steps to strengthen and expand the regulations, specifically targeting, among other things, the regulation of methane emissions from the oil and gas sector. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. Please refer to *Risk Factors - Risks Related to Oil and Gas Operations and the Industry - Legislative and regulatory initiatives and litigation related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation and related expenses* in Part I, Item 1A of this report. Meteorological or extreme weather events (whether or not related to climate change), pose additional risks to our operations, which have included temporary shut-ins of certain wells and temporary capacity constraints at third-party purchasers impacting their ability to take delivery of our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts on protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on these species. It is also possible that a federal or state agency could order a complete halt to activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling, completion, and production activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice used to stimulate production of hydrocarbons from tight shale formations. We routinely utilize hydraulic fracturing techniques in most of our drilling and completion programs. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, even on private lands, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act’s Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation’s public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids, including saltwater disposal fluids, into below-ground formations that may adversely affect drinking water sources.

Increased regulation and scrutiny on oil and gas activities involving hydraulic fracturing techniques could potentially lead to a decrease in the completion of new oil and gas wells, an increase in compliance costs, delays, and changes in federal income tax laws, all of which could adversely affect our financial position, results of operations, and cash flows. As new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local levels, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements, which could result in additional permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and gas that we are ultimately able to produce from our reserves.

We believe the trend in local, state, and federal environmental legislation and regulation will continue toward stricter standards, particularly under President Biden’s administration. While we believe we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a

material adverse impact on our financial condition and results of operations, we cannot give any assurance that we will not be adversely affected in the future.

Environmental, Health, and Safety Initiatives. We are committed to exceptional safety, health, and environmental stewardship; making a positive difference in the communities where we live and work; and transparency in reporting our progress in these areas. We set annual goals for our safety, health, and environmental program focused on minimizing the number of safety related incidents and the number and impact of spills of produced fluids. In addition, we set annual goals for GHG emissions intensity and methane emissions as a percentage of total methane produced, and as part of our current ESG initiatives, we have set goals that include minimizing flaring, reducing GHG emissions intensity, and maintaining low methane emissions intensity. We also periodically conduct audits of our operations to ensure regulatory compliance, and we strive to provide appropriate training for our employees. Minimizing air emissions as a result of leaks, venting, or flaring of gas during operations has become a major focus area as we consider this a best practice and seek to comply with regulations. While flaring is sometimes necessary, minimizing these volumes is a priority for us. To avoid flaring when possible, we restrict testing periods and connect our production to gas pipeline infrastructure as quickly as possible after well completions. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC, and can also be located at www.sec.gov. We also make available through our website our Corporate Governance Guidelines, Code of Business Conduct and Conflict of Interest Policy, Financial Code of Ethics, Human Rights Policy, and the Charters of the Audit, Compensation, Executive, and Environmental, Social and Governance committees of our Board of Directors. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in SM Energy.

Risks Related to Commodity Prices and Global Macroeconomics

Oil, gas, and NGL prices are volatile, and declines in prices may adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and gas properties depend heavily on the prices we receive for oil, gas, and NGL sales. Oil, gas, and NGL prices also affect our cash flows available for capital expenditures, debt reductions, return of capital, and other expenditures, our borrowing capacity, and the volume and value of our oil, gas, and NGL reserves. In addition, we may have oil and gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly. Please refer to *Significant Developments in 2023 and Reserves* in Part I, Items 1 and 2, *Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021* in Part II, Item 7, and *Note 1 – Summary of Significant Accounting Policies, Note 8 – Fair Value Measurements, and Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 for specific discussion.

Historically, the markets for oil, gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil, gas, and NGL prices often result from relatively minor changes in the supply of and demand for oil, gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of oil, gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for oil, gas, and NGLs;
- overall global and domestic economic conditions;
- inflation and other economic factors that contribute to market volatility;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, storage, and/or refining facilities in asset-specific or localized areas;
- liquefied natural gas deliveries to and from the United States;
- the increased demand for, price, and availability of alternative fuels or sources of energy;
- technological advances in, and regulations affecting, energy consumption and conservation;
- the ability of the members of OPEC+ to maintain effective oil price and production controls;

- political instability or armed conflict involving oil or gas producing countries or regions, such as instability in the Middle East, and the wars between Russia and Ukraine and Israel and Hamas;
- shipping channel constraints and disruptions to and from oil and gas producing countries or regions;
- actual or perceived epidemic or pandemic risks;
- strengthening and weakening of the United States dollar relative to other currencies;
- stockholder activism or activities by non-governmental organizations to limit sources of funding or restrict the exploration and production of oil, gas, and NGLs and related infrastructure; and
- governmental regulations and taxes.

Declines in oil, gas, and NGL prices would reduce our revenues and could also reduce the amount of oil, gas, and NGLs that we can produce economically, which could have a material adverse effect on our business, financial condition, liquidity, results of operations, and prospects.

Future oil, gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and development costs are capitalized when incurred. Exploratory well costs are initially capitalized, pending the determination of whether proved reserves have been discovered. If commercial quantities of proved reserves are not discovered with an exploratory well, the costs initially capitalized are expensed as dry hole costs. During the years ended December 31, 2023, and 2022, we recorded amounts related to certain unsuccessful exploration activity to exploration expense.

The capitalized costs of our oil and gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net cash flows, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Write downs for unproved properties are also evaluated for carrying costs in excess of fair value. This evaluation considers the potential for abandonment due to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. Declines in the prices of oil, gas, or NGLs, or unsuccessful exploration efforts, could cause proved and/or unproved property impairments in the future, which could have a material adverse effect on our business, financial condition, liquidity, and results of operations.

We review the carrying values of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and gas properties held for use cannot be reversed at a later date, even if oil, gas, or NGL prices increase.

Weakness in economic conditions, continued inflation, or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

Historically, the United States and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility in prices of equity and debt securities, periods of diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, inflation, and heightened levels of intervention by the United States federal government and other governments. Weakness or uncertainty in the United States economy or other large economies could have a material adverse effect on our business and financial condition. For example:

- inflation has increased the costs of our drilling and completion activities, and the costs of oilfield services, equipment, and materials in recent years and could continue or worsen and further impact our financial condition, liquidity, and results of operations, and could limit our pool of economic development opportunities;
- a potential economic recession could impact demand for oil, gas, and NGLs, and cause commodity price volatility;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our Credit Agreement could be reduced if one or more of our lenders is unable to fund its commitment;
- our ability, or the ability of our suppliers or contractors, to access the capital markets may be restricted or non-existent at a time when we or they would like, or need, to raise capital for our or their business, including for the exploration and/or development of reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection;
- the Federal Reserve could change interest rates, as they did during 2022 and 2023, which could impact borrowing costs;
- variable interest rate spread levels, including for SOFR and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based borrowings under our Credit Agreement; and
- changes in tax laws and regulations could require us to adjust our business plan.

Global geopolitical tensions may create heightened volatility in oil, gas, and NGL prices and could adversely affect our business, financial condition and results of operations.

Global geopolitical tensions, including instability in the Middle East, and the wars between Russia and Ukraine and Israel and Hamas, could lead to significant market and other disruptions, including, but not limited to: significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, shipping channel constraints and disruptions, political and social instability, political and economic sanctions, geopolitical shifts, embargoes, changes in consumer or purchaser preferences, the potential destruction of critical oil-related infrastructure, as well as increases in cyberattacks and espionage. These factors could impact our operations and the financial condition of our business as well as the global economy.

Risks Related to Oil and Gas Operations and the Industry

The loss of personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team, other key personnel, and our general labor force. The loss of their services could adversely affect our business. Our success in drilling and completing new wells and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen, and other professionals. Competition for many of these professionals can be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

Our operations are subject to complex laws and regulations, including environmental regulations, that result in substantial costs and other risks.

Federal, state, and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing, or marketing of oil, gas, and NGL production. Non-compliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to increased operational and compliance costs, substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of oil, gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in oil and gas properties, rights-of-way and easements, disposal of produced water, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, restoration standards, and oil and gas operations. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Any such delay, suspension, or termination could have a material adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, including the designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate in, could result in material costs or claims with respect to properties we own or have owned or limitations on exploration and production activities in certain locations. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and local environmental laws for emissions and for discharges of oil, gas, and NGLs or other pollutants into the air, soil, surface water, or groundwater as described in *Government Regulations* in Part I, Items 1 and 2 of this report. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a material adverse effect on us.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a common practice in the oil and gas industry used to stimulate the production of oil, gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and gas properties, including our unconventional resource plays within our Midland Basin and South Texas assets. Hydraulic fracturing involves injecting water, sand, and certain chemicals under pressure to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities, as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act. The EPA also has authority under the Clean Water Act to regulate wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process and discharged to publicly-owned wastewater treatment facilities. If the EPA implements further regulations of hydraulic fracturing, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

Certain states, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict, or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event that state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

In the recent past, several federal governmental agencies were actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In 2013, a court in California, and in 2020, the United States District Court for the District of Montana, each held that the Bureau of Land Management (“BLM”) did not comply with the National Environmental Policy Act (“NEPA”) because it did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. In 2022, the federal Ninth Circuit Court of Appeals held that two federal agencies violated NEPA, in part, by failing to evaluate the environmental impacts of well stimulation treatments such as hydraulic fracturing before authorizing unconventional oil drilling offshore. Similar cases continue to be filed. In addition, courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for, and production of, oil, gas, and NGLs, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional state or local laws, or the implementation of new regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

We will continue to be subject to uncertainty associated with new regulatory suspensions, revisions or rescissions and inconsistent state and federal regulatory mandates that could adversely affect our production.

Federal and state regulatory initiatives relating to air quality and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays.

There has been a trend toward increased air quality and GHG regulation and reduced emissions from oil and gas sources. These regulations include the New Source Performance Standards (“NSPS”), the National Emission Standards for Hazardous Air Pollutants programs, and ozone standards set under the National Ambient Air Quality Standards (“NAAQS”), among others. The adoption of additional state or local laws, or the implementation of new regulations could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows. Please refer to the *Environmental* section in Part II, Item 7 of this report for additional information about the regulation of air emissions, particularly methane emissions from the oil and gas sector.

Legislative and regulatory initiatives and litigation related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation and related expenses.

While courts have generally declined to assign direct liability for climate change to large sources of GHG emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant GHG emissions, and new claims for damages and increased government scrutiny, especially from state and local governments, will likely continue.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and the majority of states have already taken measures to reduce emissions of GHGs through various measures, including, primarily through the planned development of GHG emission inventories, participation in and/or regional GHG “cap and trade” programs, and/or transition

to clean energy. The focus on legislating and/or regulating methane could result in increased scrutiny for sources emitting high levels of methane, including during permitting processes, analysis, regulation and reduction of methane emissions as a requirement for project approval, and actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors. In 2021, the EPA proposed requirements for methane emission reductions from existing oil and gas equipment. In 2022, the EPA released a supplemental proposal expanding its initial requirements as well as updating requirements, and in 2023, proposed updates to GHG reporting requirements. The 2022 and 2023 proposals are meant to work in tandem with the programs included in the Inflation Reduction Act of 2022 (“IRA”).

The IRA imposes fees on emissions of GHGs, including methane, that exceed applicable thresholds. Our GHG emissions in 2023 did not exceed the thresholds set forth by the IRA, however, there is no assurance that we will be able to meet our goals or that we will not exceed the thresholds set forth by the IRA in the future. This and any court rulings, laws, or regulations that restrict or require reduced emissions of GHGs or introduce new climate-related regulations such as a carbon pricing system, could have an adverse effect on demand for the oil and gas that we produce, and could lead to increased operating and compliance costs, and litigation costs, which could have a material adverse impact on our business. We have a long-term goal to reduce our Scope 1 and 2 GHG emissions intensity by 50 percent by 2030, compared with base year 2019 levels, and we have an annual goal to limit our methane emissions intensity to 0.04 (metric tonnes CH₄/MBOE).

Scientists have predicted that increasing concentrations of GHGs in the earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our drilling, completion, and production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such events. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements because emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes.

Requirements to reduce gas flaring could have an adverse effect on our operations.

In the Permian Basin in Texas, where we have significant operations, there have been, and could be in the future, constraints in gas takeaway capacity which has historically led to increased gas flaring. We are subject to laws established by state and other regulatory agencies that restrict the duration and amount of natural gas that can be legally flared. These laws and regulations, including potential future regulations that may impose further restrictions on flaring, could limit the amount of oil and gas we can produce from our wells or may limit the number of wells or the locations that we can drill. We have committed to zero routine flaring at all of our operated locations, and non-routine flaring not to exceed one percent of total annual gas production, based on the full year average. Additionally, we set annual targets to limit our flaring that are tied to compensation for all employees. There is no assurance that we will be able to meet our goals with respect to flaring and any failure to meet such goals could cause reputational or other harm to our business. Any future laws or commitments may increase our operational costs, or restrict our production, which could have a material adverse effect on our financial condition, results of operations and cash flows.

The impact of extreme weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Our operations have been in the past, and may continue to be, adversely affected by the impact of extreme weather conditions. Additionally, lease stipulations designed to protect various wildlife or plant species may adversely impact our operations. In certain areas, drilling and other oil and gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs and completion equipment, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our ability to produce oil, gas, and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and/or completions operations or are unable to dispose of or recycle the water we produce at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of oil, gas, and NGLs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of, or recycle, the water produced from our wells, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil, gas, and NGLs.

Compliance with environmental regulations, surface use agreements, and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Our ability to sell oil, gas, and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines, and other transportation systems owned or operated by third-parties or by other interruptions beyond our control, which could obstruct, limit, or eliminate our access to oil, gas, and NGL markets.

The marketability of our oil, gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, pipelines, and other transportation systems, which are generally owned or operated by third parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay, or discontinuance of development plans for our properties, increases in costs, or lower price realizations. Although we have some influence over the processing and transportation of our operated production, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil, gas, and NGL production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines or processing facilities, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, transport, or market oil, gas, and NGLs.

Production may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market or other conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flows and results of operations.

We have entered into firm transportation contracts that require us to pay fixed sums of money to our counterparties regardless of quantities actually shipped, processed, or gathered. If we are unable to deliver the necessary quantities of oil, gas, NGL, or produced water to our counterparties, our results of operations, financial position, and liquidity could be adversely affected.

As of December 31, 2023, we were contractually committed to deliver a minimum of 5 MMBbl of oil through July of 2026 and 11 MMBbl of produced water through June of 2027. We may enter into additional firm transportation agreements as we expand the development of our resource plays. We do not expect to incur any material shortfalls related to our existing contractual commitments. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of operations, or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, or if we further limit our capital expenditures due to future commodity price declines or for other reasons, the requirements to pay for quantities not delivered could have a material impact on our results of operations, financial position, and liquidity.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find or acquire and develop oil, gas, and NGL reserves that are economically producible. Our properties produce oil, gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate or acquire and develop new oil, gas, and NGL reserves to replace those being depleted by production.

For future acquisitions we may complete, a successful outcome for our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price and transaction costs for the acquisition, future oil, gas, and NGL prices, the ability to reasonably estimate the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation, and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating these variables with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. Our customary review in connection with acquisitions will not necessarily reveal, or allow us to fully assess, all existing or potential problems and deficiencies with such properties. We do not inspect every well, and even when we inspect a well, we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. We often acquire interests in properties on an "as-is" basis with limited remedies for breaches of representations and warranties.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of unique risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems, and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

The results of our operations are subject to drilling and completion technique risks, and results may not meet our expectations for reserves or production. As a result, we may incur material write-downs, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Many of our operations involve utilizing the latest drilling and completion techniques as developed by us, other operators and our service providers in order to maximize production and ultimate recoveries and therefore generate the highest possible returns. Risks we face while drilling include, but are not limited to, landing our well bore outside the desired drilling zone, deviating from the desired drilling zone while drilling horizontally through the formation, the inability to run our casing the entire length of the well bore, and the inability to run tools and recover equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, the inability to fracture stimulate the planned number of stages, the inability to run tools and other equipment the entire length of the well bore during completion operations, the inability to recover such tools and other equipment, and the inability to successfully clean out the well bore after completion of the final fracture stimulation.

In addition, exploration and drilling technologies we currently use or implement in the future may become obsolete. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected. We cannot be certain we will be able to implement exploration and drilling technologies on a timely basis or at a cost that is acceptable to us.

Ultimately, the success of exploration, drilling, and completion technologies and techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or prices for oil, gas, and NGLs decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from oil and gas exploration and production companies of all sizes for the capital, equipment, expertise, labor, and materials required to operate oil and gas properties. Many of our competitors have financial, technical, and other resources exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. As a result, we may not be successful in acquiring and developing profitable properties. In addition, other companies may have a greater ability to continue drilling activities during periods of low oil or gas prices and to absorb the burden of current and future governmental regulations and taxation. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. Our inability to compete effectively with companies in any area of our business could have a material adverse impact on our business activities, financial condition, and results of operations.

The actual quantities and present value of our proved oil, gas, and NGL reserves may be less than we have estimated, and the cost to develop our reserves may be more than we have estimated.

This report and certain of our other SEC filings contain estimates of our proved oil, gas, and NGL reserves and the present value of estimated future net revenues from those reserves. The process of estimating reserves is complex and estimates are based on various assumptions, including geological and geophysical characteristics, future oil, gas, and NGL prices, drilling, completion and other capital expenditures, gathering and transportation costs, operating expenses, effects of governmental regulation, taxes, timing of operations, and availability of funds. Therefore, these estimates are inherently imprecise. In addition, our reserve estimates for properties with limited production history may be less reliable than estimates for properties with lengthy production histories.

Actual future production; prices for oil, gas, and NGLs; revenues; production taxes; development expenditures; operating expenses; and quantities of producible oil, gas, and NGL reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities of and present value related to proved reserves disclosed by us, and the actual quantities and present value may be significantly less than what we have previously estimated. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties, which we may not control.

As of December 31, 2023, 44 percent, or 263.6 MMBOE, of our estimated proved reserves were proved undeveloped. In order to develop our net proved undeveloped reserves, as of December 31, 2023, we estimate approximately \$2.8 billion of capital expenditures would be required. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

One should not assume that the standardized measure of discounted future net cash flows or PV-10 included in this report represent the current market value of our estimated proved oil, gas, and NGL reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. Please refer to *Reserves* in Part I, Items 1 and 2 of this report for discussion

regarding the prices used in estimating the present value of our proved reserves as of December 31, 2023, and to the caption *Oil and Gas Reserve Quantities* under *Critical Accounting Estimates* in Part II, Item 7 of this report for additional information.

The timing of production from oil and gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10. In addition, the 10 percent discount factor required by the SEC to calculate PV-10 for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and gas industry in general are subject.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly sell non-core assets in order to increase capital resources available for core assets and other purposes and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in other core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties, the availability of purchaser financing and purchasers willing to acquire the assets on terms we deem acceptable, or other matters or uncertainties that could impact such dispositions, including whether transactions could be consummated or completed in the form or timing and for the value that we anticipate. At times, we may be required to retain certain liabilities or agree to indemnify buyers in connection with such asset sales. The magnitude of such retained liabilities or of the indemnification obligations may be difficult to quantify at the time of the transaction and ultimately could be material.

We rely on third-party service providers to conduct drilling and completion and other related operations.

We rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, gas, and NGLs, prevailing economic conditions, and financial, business, and other factors. Future periods of sustained low commodity prices could occur and could cause third-party service providers to consolidate or declare bankruptcy, which could limit our options for engaging such providers. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally rely on title due diligence reports when acquiring oil and gas leasehold interests, and we obtain title opinions prior to commencing initial drilling operations on the properties we operate. Title to the properties in which we have an interest may be impaired by title defects that may not be identified in the due diligence title reports or title opinions we obtain, or such defects may not be cured following identification. A material title defect can reduce the value of a property or render it worthless, thus adversely affecting our oil and gas reserves, financial condition, results of operations, and operating cash flow, and may also impair the value of or render adjacent properties uneconomic to develop. Undeveloped acreage has greater risk of title defects than developed acreage and title insurance is not generally available for oil and gas properties.

Oil and gas drilling, completion, and production activities are subject to numerous risks, including the risk that no commercially producible oil, gas, or NGLs will be found.

The cost of drilling and completing wells is often uncertain, and oil, gas, or NGLs drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors may include, but are not limited to:

- supply chain issues, including cost increases and availability of equipment or materials;
- unexpected adverse drilling or completion conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes, tornadoes, flooding, wildfires or other adverse weather conditions;
- operational restrictions resulting from seismicity concerns;
- governmental permitting delays;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if oil, gas, or NGLs are present, or whether they can be produced economically. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of oil, gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore or develop our properties.

Results in newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. We, and the industry, generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of new plays; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

We may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases for such acreage will expire, and we will lose our right to develop the related properties. Our total net acreage as of February 8, 2024, that is scheduled to expire over the next three years, represents approximately 19 percent of our total net undeveloped acreage as of December 31, 2023. Although we have identified numerous potential drilling locations, we may not be able to economically drill for and produce oil, gas, or NGLs from all of them, and our actual drilling activities may materially differ from those presently identified, which could adversely affect our financial condition, results of operations and operating cash flow.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, result in increased lease operating expenses and adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil, gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other market conditions, including declines in oil, gas, and NGL prices. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell. We do not believe the loss of any single purchaser would materially impact our operating results, as we have numerous options for purchasers in each of our operating areas for our oil, gas, and NGL production. Please refer to *Concentration of Credit Risk and Major Customers* in *Note 1 – Summary of Significant Accounting Policies*, in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers. Additionally, the inability of our co-owners to pay joint interest billings could negatively impact our cash flows and financial ability to drill and complete current and future wells.

We are subject to operating and environmental risks and hazards that could result in substantial losses or liabilities that may not be fully insured.

Oil and gas operations are subject to many risks, including human error and accidents, that could cause personal injury, death, property damage, well blowouts, craterings, explosions, uncontrollable flows of oil, gas and NGLs, or well fluids, releases or spills of completion fluids, spills or releases from facilities and equipment used to deliver or store these materials, spills or releases of brine or other produced or flowback water, subsurface conditions that prevent us from stimulating the planned number of completion stages, accessing the entirety of the wellbore with our tools during completion, or removing materials from the wellbore to allow production to begin, fires, adverse weather such as hurricanes or tornadoes, freezing conditions, wildfires, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, pollution, seismic events, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occur, we could sustain substantial losses.

In response to increased seismic activity in the Permian Basin in Texas, the Railroad Commission of Texas (“RRC”) has developed a seismic review process for injection wells near qualifying seismic activity. As a result of the seismic review process, the RRC may declare an area to be a Seismic Response Area (“SRA”) and may adjust limits for injection rates and pressure, require bottom-hole pressure tests, or modify, suspend, or terminate injection well permits within the SRA. If an SRA is declared within an area of our operations, our ability to dispose of produced water may be adversely affected, and as a result, we may be forced to shut-in injection wells or find alternate produced water disposal options which could affect production and therefore oil, gas, and NGL production revenue, and could cause us to incur additional capital or operating expense. The declaration of SRAs has required us to adjust the areas where we seek permits for injection wells to areas or formations that are less desirable, and could further restrict the areas where we are able to obtain and operate under such permits without restrictions. Additionally, we could be subject to third-party claims and liability based on allegations that our operations caused or contributed to seismic events that resulted in damage to property or personal injury, or that are otherwise related to seismic events.

If we experience any of the problems with well stimulation, completion activities, and disposal referenced above, our ability to explore for and produce oil, gas, and NGLs may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of the need to shut down, abandon, or relocate drilling operations, the need to modify drill sites to lessen the risk of spills or releases, the need to investigate and/or remediate any spills, releases or ground water contamination that might have occurred, and the need to suspend our operations.

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling, and disposal of materials, including produced water, solid and hazardous wastes, and petroleum hydrocarbons. We may incur joint and several, and/or strict liability under applicable United States federal and state environmental laws in connection with releases of hazardous substances at, on, under, or from our leased or owned properties, some of which have been used for oil and gas exploration and production activities for a number of years, often by third-parties not under our control. For our outside-operated properties, we are dependent on the operator for operational and regulatory compliance and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or therefrom could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including CERCLA or the Superfund law, RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under various implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury or property damage, including induced seismicity damage, allegedly caused by the release of petroleum hydrocarbons or other hazardous substances into the environment. As a result, we may incur substantial liabilities to third-parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by environmental damage that occurs gradually over time is appropriate for us at this time given the nature of our operations and the nature and cost of such coverage. Further, we may elect not to obtain insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer an uninsured material loss.

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

Some of our properties 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 the nature and timing of drilling and operational activities, the operator’s skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of 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 expenditures of such properties. These limitations and our dependence on the operator and other working interest owners in these projects could cause us to incur unexpected future costs.

Risks Related to Debt, Liquidity, and Access to Capital

Lower oil, gas, or NGL prices could limit our ability to borrow under our Credit Agreement.

As of December 31, 2023, the borrowing base and aggregate lender commitments under our Credit Agreement were \$2.5 billion and \$1.25 billion, respectively. The borrowing base is subject to semi-annual redetermination based on the bank group’s assessment of the value of our proved reserves, which in turn is impacted by oil, gas, and NGL prices. The next borrowing base redetermination date is scheduled for April 1, 2024. Divestitures of properties, incurrence of additional debt, or declines in commodity prices could limit our borrowing base and reduce the amount we can borrow under our Credit Agreement, which could in turn impact, among other things, our ability to service our debt, fund our capital program, or compete for the acquisition of new properties.

Substantial capital is required to develop and replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce oil, gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for oil, gas, and NGL sales, our success in locating, developing, and acquiring new reserves, and the orderly functioning of credit and capital markets. If our cash flows from operations are less than expected, we may reduce our planned capital expenditures. If we cannot access sufficient liquidity under our Credit Agreement, or raise additional funds through debt or equity financing or the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Downgrades in our credit ratings by various credit rating agencies could impact our access to capital and have a material adverse effect on our business and financial condition.

Downgrades of our credit ratings could have material adverse consequences on our business and future prospects and could:

- limit our ability to access capital markets, including for the purpose of refinancing our existing debt;
- cause us to refinance or issue debt with less favorable terms and conditions, which may restrict, among other things, our ability to make any dividend payments or repurchase shares;
- negatively impact lenders' willingness to transact business with us, which could impact our ability to obtain favorable terms and conditions under our Credit Agreement;
- negatively impact current and prospective customers' willingness to transact business with us;
- impose additional insurance, guarantee, bonding, and collateral requirements;
- limit our access to bank and third-party guarantees, surety bonds, and letters of credit; and
- cause our suppliers and financial institutions to lower or eliminate the level of credit provided through payment terms or intraday funding when dealing with us, thereby increasing the need for higher levels of cash on hand, which would decrease our ability to repay outstanding indebtedness.

We cannot provide assurance that any of our current credit ratings will remain in effect for any given period of time or that a credit rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant.

Our commodity derivative contract activities may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales.

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, we regularly enter into commodity derivative contracts. Our commodity derivative contracts typically include price swap and collar arrangements for oil, gas, and NGLs. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

In addition, commodity derivative contracts may limit the prices we receive for our oil, gas, and NGL sales if oil, gas, or NGL prices rise substantially over the price established by the commodity derivative contract. Please refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional detail regarding our commodity derivative contracts.

The amount of our debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2023, we had \$1.6 billion of aggregate principal amount outstanding of Senior Notes with maturities through 2028, as further discussed and defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. We had no outstanding balance on our revolving credit facility and had \$1.2 billion of available borrowing capacity under our Credit Agreement as of December 31, 2023. Our long-term debt represented 30 percent of our total book capitalization as of December 31, 2023.

The amounts of our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;
- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to capital investments;

- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;
- placing us at a competitive disadvantage compared to our competitors with less debt; and
- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our Credit Agreement or from other sources, we might not be able to service our debt, issue additional debt, or fund our planned capital expenditures and other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, and/or restructure or refinance our debt. We might not be able to sell our equity, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our Credit Agreement and any future credit agreements, may prohibit us from pursuing any of these alternatives.

As discussed above, our Credit Agreement is subject to periodic borrowing base redeterminations. At times when we have an outstanding balance, we could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate adjustments to our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt arrangements contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements, including our Credit Agreement and the indentures governing our Senior Notes, contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests, including restrictions on incurring debt, issuing dividends, repurchasing common stock, selling assets, creating liens, entering into transactions with affiliates, and merging, consolidating, or selling our assets. Our ability to borrow under our Credit Agreement is subject to compliance with certain financial and non-financial covenants, as outlined in the Credit Agreement. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion. These restrictions on our ability to operate our business could significantly harm us by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

Negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole could adversely affect our business, operations, and our ability to attract capital.

Certain segments of the public as a whole, and the investment community in particular, have developed negative sentiment toward our industry. In recent years, equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment management firms, sovereign wealth and pension funds, university endowments and other investment advisors, have adopted policies to discontinue or reduce their investments in the oil and gas sector based on social and environmental considerations. Furthermore, other influential stakeholders have pressured commercial and investment banks and other service providers to reduce or cease financing of oil and gas companies and related infrastructure projects.

Such developments, including increased focus on environmental, social and governance matters and initiatives aimed at limiting climate change and reducing air pollution, and changes in federal income tax laws could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Risks Related to Corporate Governance and Ownership of Public Equity Securities

Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment, which could adversely affect the price of our common stock.

Delaware corporate law and our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control of us or our management. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price investors are willing to pay in the future for shares of our common stock.

In addition, stockholder activism in our industry has been present in recent years, and if investors seek to exert influence or affect changes to our business that we do not believe are in the long-term best interests of our stockholders, such actions could adversely impact our business by, among other things, distracting our Board of Directors and management team, causing us to incur unexpected advisory fees and other related costs, impacting execution of our strategic objectives, and creating unnecessary market uncertainty.

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2023, to February 8, 2024, the intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of \$24.66 per share in March 2023 to a high of \$43.73 per share in October 2023. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include, in addition to the other risk factors set forth herein, the following:

- changes in oil, gas, or NGL prices;
- changes in the outlook for regional, national, or global commodity supply and demand;
- variations in drilling, recompletion, and operating activity;
- inflation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- increased volatility due to the impacts of algorithmic trading practices;
- future sales of our common stock;
- negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole;
- changes in the national and global economic outlook, including potential impacts from trade agreements; and
- international trade relationships, potentially including the effects of trade restrictions or tariffs affecting the raw materials we utilize and the commodities we produce in our business.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

We may not always pay dividends on our common stock or repurchase common stock under our Stock Repurchase Program.

Payment of future dividends remains at the discretion of our Board of Directors, and common stock repurchases under our Stock Repurchase Program remain at the discretion of our Board of Directors and certain authorized officers of the Company. Decisions regarding the payment of dividends and the repurchase of common stock will continue to depend on our earnings, capital requirements, financial condition, general market and economic conditions, applicable legal requirements, the market price of our common stock, and other factors. The payment of dividends and the repurchase of our common stock are each subject to covenants in our Credit Agreement and in the indentures governing our Senior Notes that could limit our ability to make certain restricted payments including dividends and common stock repurchases. Our Board of Directors may determine in the future to reduce the current annual dividend rate or discontinue the payment of dividends altogether. The value of shares authorized for repurchase by the Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of our shares will be repurchased.

General Risk Factors

Our increasing dependence on digital technologies puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruptions or financial loss.

We are subject to cybersecurity risks. The oil and gas industry, and our business, are increasingly dependent on digital technology. We use digital technology to conduct certain aspects of our drilling development, production and gathering activities, manage drilling rigs and completion equipment, gather and interpret seismic data, conduct reservoir modeling, record financial and operating data, and maintain employee and other databases. Our service providers, including those who gather, process, and market our oil, gas, and NGLs, are also increasingly reliant on digital technology. Our and their reliance on this technology increasingly puts us at risk for technology system failures, data or network disruptions, cyberattacks and other breaches in cybersecurity. Power failures, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, flood, human error or other means could significantly impair our ability to conduct our business.

Cybersecurity attacks are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, cash, or other assets, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Deliberate attacks on, or security

breaches in our systems, infrastructure, the systems and infrastructure of third-parties, or cloud-based applications could lead to disclosure of confidential information, a corruption or loss of our proprietary data, delays in production or exploration activities, difficulty in completing or settling transactions, challenges in maintaining our books and records, environmental damage, communication or other operational disruptions, and liability to third parties. Any insurance we might obtain in the future may not provide adequate protection from these risks. Any such events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. As these cyber risks continue to evolve and our dependence on digital technologies grows, we may be required to expend significant additional resources to continue to modify or enhance our protective measures and remediate cyber vulnerabilities.

Please refer to *Cybersecurity Risk Management, Strategy, and Governance* in Item 1C of this report for discussion of the Audit Committee's role in cybersecurity governance. We did not experience any material cybersecurity incidents during 2023, however there can be no assurance that the measures we have taken to address information technology ("IT") and cybersecurity risks will prove effective in the future.

We are incorporating artificial intelligence technologies into our processes and these technologies may present business, compliance, and reputational risks.

Our business increasingly utilizes artificial intelligence ("AI"), machine learning, and automated decision making to improve our processes. Issues in the development and use of AI, combined with an uncertain regulatory environment, may result in new or enhanced governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability, or other adverse consequences to our business operations, all of which could adversely affect our business, results of operations, and financial condition.

In addition, it is possible that AI and machine learning-technology could, unbeknownst to us, be improperly utilized by employees while carrying out their responsibilities. The use of AI can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or generating content that appears correct but is factually inaccurate, misleading, or otherwise flawed, which could harm our reputation and business and expose us to risks related to inaccuracies or errors in the output of such technologies. It is not possible to predict all of the risks related to the use of AI, machine learning and automated decision making, and developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations may adversely affect our ability to develop and use such technologies or subject us to liability. If we fail to successfully integrate AI into our business processes, or if we fail to keep pace with rapidly evolving AI technological developments, including attracting and retaining talented data scientists, data engineers, and programmers, we may face a competitive disadvantage.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.

As an oil, gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts, including armed attacks on shipping channels. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel, or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

The threat of terrorism and the impact of military and other actions have caused instability in world financial markets and could lead to increased volatility in prices for oil, gas, and NGLs, all of which could adversely affect the markets for our production. Energy assets might be specific targets of terrorist attacks. Depending on their occurrence and ultimate magnitude, terrorist threats or attacks could have a material adverse effect on our business, financial condition, or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 1C. CYBERSECURITY RISK MANAGEMENT, STRATEGY, AND GOVERNANCE

Risk Management and Strategy

We believe that mitigating cybersecurity risks is the responsibility of every employee. We take a preventative approach with respect to cybersecurity threats by building a resilient cybersecurity culture and strong IT infrastructure. Our processes for assessing, identifying, and managing material risks from cybersecurity threats include:

- monitoring the threat landscape and taking measures to enhance our cybersecurity program to adapt to new and developing risks;
- ongoing training, testing, and utilizing other forms of social engineering awareness and education for our employees;

- using cybersecurity systems and tools to monitor endpoints and environment logs in a centralized security information and event management system with capabilities for reporting and alerting on known threats and anomalous behaviors;
- assessing the cybersecurity practices and external ratings and assessments of certain of our third-party technology and data vendors and service providers, and maintaining preventative controls and monitoring systems related to these partners;
- creating and testing various incident response plans to hypothetical cybersecurity attacks in order to quickly assess and respond to potential and actual threats;
- utilizing third-party experts to perform penetration testing and scanning of our systems for vulnerabilities;
- obtaining third-party security maturity assessments, benchmarking, and security effectiveness ratings of our cybersecurity program; and
- maintaining a retainer for incident response services with a trusted cybersecurity partner in order to quickly respond, investigate, contain, and recover in the event of a cybersecurity incident.

We have structured our cybersecurity risk management program according to the National Institute of Standards and Technology Cybersecurity Framework. We strive to employ cybersecurity best practices, including implementing new technologies to proactively monitor new threats and vulnerabilities and reduce risk; maintaining a Cybersecurity Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan; and regularly updating our response planning and protocols. We have integrated our cybersecurity processes into our overall risk management program, thereby establishing a comprehensive approach by which we determine and implement strategies designed to manage external, strategic, operational and financial risks to our business, including cybersecurity threats.

We utilize a wide range of protective cybersecurity technologies and tools, including, but not limited to, encryption, firewalls, endpoint detection and response, security information and event management, multi-factor authentication, and threat intelligence feeds. In addition, we use an information security risk management approach that includes monitoring security threats and trends in the industry, analyzing potential security risks that could impact the business, partnering with industry recognized security organizations, and coordinating an appropriate response should the need arise.

Cybersecurity threats and incidents could have a material impact on our financial condition and results of operations. A successful cyber-attack could lead to operational disruptions, financial losses, regulatory penalties, reputational damage, and legal liabilities. In some cases, the costs associated with investigating and remediating a cybersecurity incident, as well as potential litigation and regulatory fines, could result in a material impact to our financial condition and results of operations. During 2023, we did not experience any cybersecurity incidents that materially affected or are reasonably likely to materially affect us, including our business strategy, results of operations or financial condition, however, there can be no assurance that the measures we have taken to address IT and cybersecurity risks will prove effective in the future. For additional discussion of the IT and cybersecurity risks facing our business, please refer to *Risk Factors* in Part 1, Item 1A of this report.

We prioritize investment in cybersecurity risk management and governance. We continually assess the adequacy of our resources and capabilities to address emerging threats, regulatory requirements, and changes in technology. As cybersecurity threats evolve, we may need to further enhance our processes and technologies, which could require additional financial resources.

Governance

Our Board of Directors receives regular updates on relevant IT matters affecting the Company, including cybersecurity risks and mitigation strategies. In addition to the general oversight provided by the full Board of Directors, the Audit Committee is responsible for oversight of our risk assessment and management processes, including with respect to IT and cybersecurity risks. The Audit Committee receives a quarterly cybersecurity report and regular updates from our Vice President and Chief Information Officer and our Director of Cybersecurity Risk and Business Continuity, which includes, among other information, the steps management has taken, and the specific guidelines and policies that have been established, to monitor, control, mitigate and report exposure to IT and cybersecurity risk.

We have established a Cyber Incident Response Team (“CIRT”) to provide an efficient, effective, and orderly response to technology related incidents and our Cybersecurity Incident Response Plan contains protocols for communication within this team and reporting to executive management and the Audit Committee.

The CIRT is led by our Vice President and Chief Information Officer and Director of Cybersecurity Risk and Business Continuity. Together, these professionals are responsible for assessing and managing cybersecurity risks and they lead a team of specialized technologists entrusted with ensuring the functionality, continuity, and security of our technology infrastructure and data. Our Vice President and Chief Information Officer is a seasoned IT professional with over 28 years of experience encompassing all facets of IT within the energy industry. His extensive background comprises managing IT service delivery, designing and administering secure solutions, establishing robust IT and Internet of Things infrastructures, and effectively managing technology-related risks. His skill set includes proficiency in threat mitigation, comprehensive risk assessment, and integration of cybersecurity strategies into business operations designed to safeguard critical assets and sensitive data. He reports to our Executive Vice President and Chief Financial Officer. Our Director of Cybersecurity Risk and Business Continuity has over 23 years of experience in the IT field with a

majority of that time focused on designing, building and maintaining technology systems. His experience includes implementing security solutions and processes with a focus on adapting to the evolving cybersecurity threat landscape. He is a skilled leader and reports to our Executive Vice President and Chief Financial Officer.

ITEM 3. LEGAL PROCEEDINGS

At times, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing of this report, no legal proceedings are pending against us that we believe individually or collectively are likely to have a material adverse effect upon our financial condition, results of operations, or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

PART II

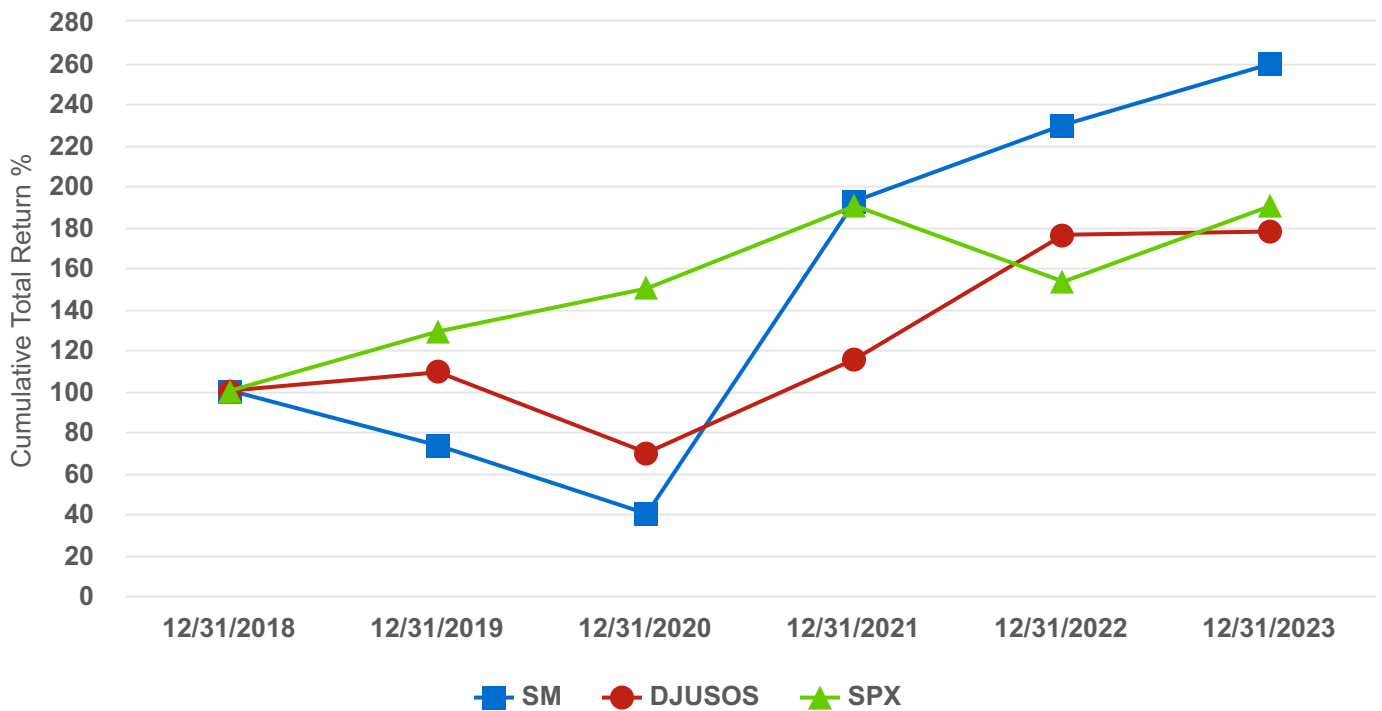
ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is currently traded on the New York Stock Exchange under the ticker symbol “SM.” For dividend information, please refer to the caption *Uses of Cash in Overview of Liquidity and Capital Resources* in Item 7 of this report. Information regarding the SM Energy Equity Incentive Compensation Plan, as amended and restated effective as of May 22, 2018 (the “Equity Plan”), and the securities authorized under the Equity Plan is included below.

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2018, and ending December 31, 2023, with the cumulative total returns of the Dow Jones Exploration and Production Index (“DJUSOS”), and the Standard & Poor’s 500 Stock Index (“SPX”).

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS



The preceding information under the caption *Performance Graph* shall be deemed to be furnished, but not filed with the SEC.

*Holder*s. As of February 8, 2024, the number of record holders of our common stock was 102. A substantially greater number of holders of our common stock are beneficial holders, whose shares of record are held by banks, brokers, and other financial institutions.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. The following table provides information about purchases made by us and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and months, and the year ended December 31, 2023, of shares of our common stock, which is the sole class of equity securities registered by us pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS				
Period	Total Number of Shares Purchased ⁽¹⁾	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program ⁽²⁾	Maximum Number or Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (as of the period end date) ⁽²⁾
First quarter of 2023	1,413,758	\$ 28.32	1,413,758	\$ 402,780,476
Second quarter of 2023	2,550,976	\$ 26.95	2,550,706	\$ 334,036,922
Third quarter of 2023	2,600,605	\$ 40.07	2,351,642	\$ 237,700,848
10/01/2023 - 10/31/2023	—	\$ —	—	\$ 237,700,848
11/01/2023 - 11/30/2023	614,729	\$ 37.16	614,729	\$ 214,854,687
12/01/2023 - 12/31/2023	—	\$ —	—	\$ 214,854,687
Total	7,180,068	\$ 32.85	6,930,835	

⁽¹⁾ 249,233 shares purchased by us in 2023 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying Restricted Stock Units (“RSU” or “RSUs”) issued under the terms of award agreements granted under the Equity Plan.

⁽²⁾ Our Stock Repurchase Program, which authorizes us to repurchase up to \$500.0 million in aggregate value of our common stock through December 31, 2024, permits us to repurchase our shares from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws and subject to certain provisions of our Credit Agreement and the indentures governing our Senior Notes. The timing, as well as the number and value of shares repurchased under the Stock Repurchase Program, is determined by certain authorized officers of the Company at their discretion and depends on a variety of factors, including the market price of our common stock, general market and economic conditions and applicable legal requirements. The value of shares authorized for repurchase by our Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of our shares will be repurchased. During the year ended December 31, 2023, we repurchased and subsequently retired 6,930,835 shares of our common stock under the Stock Repurchase Program at a weighted-average share price of \$32.89 for a total cost of \$228.0 million, excluding excise taxes, commissions and fees.

Our payment of cash dividends to our stockholders and repurchases of our common stock are each subject to certain covenants under the terms of our Credit Agreement and Senior Notes. Based on our current performance, we do not anticipate that any of these covenants will limit our potential repurchases of our common stock or our payment of dividends at our current rate for the foreseeable future if any dividends are declared by our Board of Directors.

During the year ended December 31, 2023, we paid \$71.6 million in dividends to our stockholders. Dividends paid reflects \$0.60 per share during the year ended December 31, 2023. During 2023, our Board of Directors approved a 20 percent increase to our fixed dividend to \$0.72 per share annually, to be paid in quarterly increments of \$0.18 per share, beginning in the first quarter of 2024. We currently intend to continue paying dividends to our stockholders for the foreseeable future, subject to our future earnings, our financial condition, covenants under our Credit Agreement and indentures governing each series of our outstanding Senior Notes, and other factors that could arise. The payment and amount of future dividends remain at the discretion of our Board of Directors.

ITEM 6. [RESERVED]

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

The following discussion includes forward-looking statements. Please refer to the *Cautionary Information about Forward-Looking Statements* section of this report for important information about these types of statements.

Overview of the Company

General Overview

Our purpose is to make people's lives better by responsibly producing energy supplies, contributing to domestic energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets by maintaining and optimizing our high-quality asset portfolio, generating cash flows, and maintaining a strong balance sheet. Our team executes this strategy by prioritizing safety, technological innovation, and stewardship of natural resources, all of which are integral to our corporate culture. Our near-term goals include continuing to return value to stockholders through our Stock Repurchase Program and fixed dividend payments, and by focusing on continued operational excellence.

Our asset portfolio is comprised of high-quality assets in the Midland Basin of West Texas and in the Maverick Basin of South Texas that we believe are capable of generating strong returns in the current macroeconomic environment and provide resilience to commodity price risk and volatility. We seek to maximize returns and increase the value of our top-tier assets through disciplined capital spending, strategic acquisitions, and continued development and optimization of our existing assets. We believe that our high-quality assets facilitate a sustainable approach to prioritizing operational execution, maintaining a strong balance sheet, generating cash flows, returning capital to stockholders, and maintaining financial flexibility.

We are committed to exceptional safety, health, and environmental stewardship; supporting the professional development of a diverse and thriving team of employees; building and maintaining partnerships with our stakeholders by investing in and connecting with the communities where we live and work; and transparency in reporting our progress in these areas. The Environmental, Social and Governance Committee of our Board of Directors oversees, among other things, the effectiveness of our ESG policies, programs and initiatives, monitors and responds to emerging issues, and, together with management, reports to our Board of Directors regarding such matters. Further demonstrating our commitment to sustainable operations and environmental stewardship, compensation for our executives and eligible employees under our long-term incentive plan, and compensation for all employees under our short-term incentive plan is calculated based on, in part, certain Company-wide, performance-based metrics that include key financial, operational, environmental, health, and safety measures. Please refer to our Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders to be filed within 120 days from December 31, 2023, for additional discussion.

We are impacted by global commodity and financial markets that remain subject to heightened levels of uncertainty and volatility. While the rate of inflation in the United States has decreased since the beginning of the year and the average rate of inflation in 2023 was lower than it was in 2022, inflation continues to impact certain aspects of our business. Continued oil production curtailment agreements among OPEC+, instability in the Middle East, economic and trade sanctions associated with the wars between Russia and Ukraine and Israel and Hamas, United States Federal Reserve monetary policy, shipping channel constraints and disruptions, and changes in global oil inventory in storage have driven commodity price volatility, contributed to instances of supply chain disruptions and fluctuations in interest rates, and could have further industry-specific impacts that may require us to adjust our business plan. Future impacts of these and other events on commodity and financial markets are inherently unpredictable. Despite continuing uncertainty, we expect to maximize the value of our high-quality asset base and sustain strong operational performance and financial stability. We remain focused on returning capital to stockholders through cash flow generation.

Outlook

We expect our total 2024 capital program to be between \$1.16 billion and \$1.20 billion, excluding acquisitions, which we expect to fund with cash flows from operations and cash on hand. We plan to focus our 2024 capital program on highly economic oil development projects in both our Midland Basin and South Texas assets, including the assets we acquired during 2023. We expect to repurchase additional shares of our outstanding common stock through our Stock Repurchase Program during 2024, under which \$214.9 million remains available for repurchases through December 31, 2024, as of the filing of this report.

2023 Financial and Operational Highlights

During 2023, we increased the amount of capital we returned to our stockholders, compared with 2022, through repurchases of our outstanding common stock under our Stock Repurchase Program and our fixed quarterly dividend payments, and we expanded our Midland Basin asset position. During the year ended December 31, 2023, we repurchased and subsequently retired 6.9 million shares of our common stock at a cost of \$228.0 million, excluding excise taxes, commissions, and fees; we paid dividends of \$0.60 per share, an increase from \$0.16 per share paid during the year ended December 31, 2022; and we announced a 20 percent increase to our fixed dividend to \$0.72 per share annually, to be paid in quarterly increments of \$0.18 per share, beginning in the first quarter of 2024. Additionally, we executed strategic acquisitions, exchanges, and leasing activity in the Midland Basin, enabling us to enhance

our capital efficiency by blocking up acreage and maintaining high working interests. Please refer to *Note 3 – Equity* and *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion.

Financial and Operational Results. Average net daily equivalent production for the year ended December 31, 2023, increased five percent to 152.0 MBOE, compared with 145.1 MBOE for 2022 as a result of an increased number of completions in 2023 compared with 2022. The total increase consisted of a 20 percent increase from our South Texas assets, partially offset by a seven percent decrease from our Midland Basin assets. These changes were a result of the timing of well completions, and the timing of capital expenditures during 2022 and 2023.

Realized prices for oil, gas, and NGLs decreased 19 percent, 61 percent, and 35 percent, respectively, for the year ended December 31, 2023, compared with 2022, as a result of decreases in benchmark commodity prices during 2023. Total realized price per BOE decreased 33 percent for the year ended December 31, 2023, compared with 2022, resulting in a 29 percent decrease in oil, gas, and NGL production revenue, which was \$2.4 billion for the year ended December 31, 2023, compared with \$3.3 billion for 2022. Oil, gas, and NGL production expense of \$10.16 per BOE for the year ended December 31, 2023, decreased 13 percent compared with 2022, primarily as a result of decreases in production tax expense per BOE, transportation costs per BOE, and ad valorem tax expense per BOE, partially offset by an increase in LOE per BOE.

We recorded a net derivative gain of \$68.2 million for the year ended December 31, 2023, compared to a net derivative loss of \$374.0 million for 2022. These amounts include a net derivative settlement gain of \$26.9 million for the year ended December 31, 2023, and a net derivative settlement loss of \$710.7 million for the year ended December 31, 2022.

Operational activities during the year ended December 31, 2023, resulted in the following:

- Net cash provided by operating activities of \$1.6 billion, compared with \$1.7 billion for 2022.
- Net income of \$817.9 million, or \$6.86 per diluted share, compared with net income of \$1.1 billion, or \$8.96 per diluted share for 2022.
- Adjusted EBITDAX, a non-GAAP financial measure, of \$1.7 billion, compared with \$1.9 billion for 2022. Please refer to *Non-GAAP Financial Measures* below for additional discussion, including our definition of adjusted EBITDAX and reconciliations to net income and net cash provided by operating activities.
- Total estimated net proved reserves as of December 31, 2023, increased 13 percent from December 31, 2022, to 604.9 MMBOE, of which, 58 percent were liquids (oil and NGLs) and 56 percent were proved developed reserves. The increase primarily consisted of revisions of previous estimates of 113.9 MMBOE related to infill reserves in both our South Texas and Midland Basin programs, partially offset by 55.5 MMBOE of production during 2023. Our proved reserve life index increased to 10.9 years as of December 31, 2023, compared with 10.1 years as of December 31, 2022. Please refer to *Reserves* in Part I, Items 1 and 2 of this report for additional discussion. The standardized measure of discounted future net cash flows was \$6.3 billion as of December 31, 2023, compared with \$10.0 billion as of December 31, 2022, which was a decrease of 37 percent year-over-year primarily driven by decreases in benchmark commodity prices during 2023. Please refer to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Operational Activities. During 2023, successful operational execution resulted in strong well performance in the RockStar and Sweetie Peck areas of our Midland Basin position, and allowed us to maximize capital efficiency. Our South Texas program benefited from continued successful delineation and development of the Austin Chalk formation in addition to sustained strong performance of our Eagle Ford shale wells. Our continued success in both our Midland Basin and South Texas programs is attributable to our top-tier assets and technical teams, and our commitment to geoscience, technology, and innovation.

In our Midland Basin program, we averaged three drilling rigs and one completion crew during 2023. We added a fourth drilling rig at the end of the third quarter to begin drilling on our newly acquired Klondike acreage. We drilled 54 gross (37 net) wells, completed 64 gross (54 net) wells, and acquired additional working interests in five net wells during 2023. Average net daily equivalent production volumes decreased year-over-year by seven percent to 75.4 MBOE. Costs incurred during 2023 totaled \$768.1 million, or 62 percent of our total 2023 costs incurred. Drilling and completion activities within our RockStar and Sweetie Peck positions in the Midland Basin were focused primarily on developing the Spraberry and Wolfcamp formations.

In our South Texas program, we averaged two drilling rigs and one completion crew during 2023. We drilled 46 gross (46 net) wells and completed 38 gross (37 net) wells during 2023. Average net daily equivalent production volumes increased year-over-year by 20 percent to 76.7 MBOE. Costs incurred during 2023 totaled \$423.5 million, or 34 percent of our total 2023 costs incurred. Drilling and completion activities in South Texas during 2023 were primarily focused on delineating and developing the Austin Chalk formation.

The table below provides a summary of changes in our drilled but not completed well count and current year drilling, completion, and acquisition activity in our operated programs for the year ended December 31, 2023:

	Midland Basin		South Texas ⁽¹⁾		Total	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2022	49	40	29	28	78	69
Wells drilled	54	37	46	46	100	83
Wells completed	(64)	(54)	(38)	(37)	(102)	(91)
Wells acquired ⁽²⁾	—	5	—	—	—	5
Wells drilled but not completed at December 31, 2023	<u>39</u>	<u>29</u>	<u>37</u>	<u>37</u>	<u>76</u>	<u>66</u>

Note: Amounts may not calculate due to rounding.

⁽¹⁾ As of December 31, 2022, and 2023, the drilled but not completed well count included nine gross (nine net) wells that were not included in our five-year development plan, eight of which were in the Eagle Ford shale.

⁽²⁾ Amount relates to additional working interests acquired in drilled but not completed wells during the year ended December 31, 2023.

Costs Incurred. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	For the Year Ended December 31, 2023
	(in millions)
Development costs	\$ 931.8
Exploration costs	172.6
Acquisitions	
Proved properties	65.0
Unproved properties	65.6
Total, including asset retirement obligations ⁽¹⁾	<u>\$ 1,235.0</u>

⁽¹⁾ Please refer to the caption *Costs Incurred in Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Production Results. The table below presents the disaggregation of our net production volumes by product type for each of our assets for the year ended December 31, 2023:

	Midland Basin	South Texas	Total
Net production volumes:			
Oil (MMBbl)	17.5	6.3	23.8
Gas (Bcf)	59.8	72.6	132.4
NGLs (MMBbl)	—	9.6	9.7
Equivalent (MMBOE)	27.5	28.0	55.5
Average net daily equivalent (MBOE per day)	75.4	76.7	152.0
Relative percentage	50 %	50 %	100 %

Note: Amounts may not calculate due to rounding.

Net equivalent production increased five percent for the year ended December 31, 2023, compared with 2022, comprised of a 20 percent increase from our South Texas assets, partially offset by a seven percent decrease from our Midland Basin assets. Please refer to *Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021* below for additional discussion of production.

Acquisition Activity. During 2023, we acquired approximately 20,000 net acres of oil and gas properties in Dawson and northern Martin counties, Texas. Additionally, in the Midland Basin, we added approximately 9,100 net acres through organic leasing activity, we completed an asset exchange, and we acquired additional working interests in certain wells. Please refer to *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effect of net derivative settlements. While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location and transportation differentials, and contracted pricing benchmarks for these products.

The following table summarizes commodity price data, as well as the effect of net derivative settlements, for the years ended December 31, 2023, 2022, and 2021:

	For the Years Ended December 31,		
	2023	2022	2021
Oil (per Bbl):			
Average NYMEX contract monthly price	\$ 77.62	\$ 94.23	\$ 67.92
Realized price	\$ 76.28	\$ 94.67	\$ 67.72
Effect of oil net derivative settlements	\$ (1.13)	\$ (21.46)	\$ (18.73)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	\$ 2.74	\$ 6.64	\$ 3.84
Realized price (per Mcf)	\$ 2.48	\$ 6.28	\$ 4.85
Effect of gas net derivative settlements (per Mcf)	\$ 0.37	\$ (1.36)	\$ (1.41)
NGLs (per Bbl):			
Average OPIS price ⁽¹⁾	\$ 27.71	\$ 43.48	\$ 36.65
Realized price	\$ 23.02	\$ 35.66	\$ 33.67
Effect of NGL net derivative settlements	\$ 0.48	\$ (3.06)	\$ (13.68)

⁽¹⁾ Effective January 1, 2023, average OPIS price per barrel of NGL, historical or strip, assumes a composite barrel product mix of 42% Ethane, 28% Propane, 6% Isobutane, 11% Normal Butane, and 13% Natural Gasoline. For periods prior to 2023, average OPIS price per barrel of NGL, historical or strip, assumed a composite barrel product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline. These product mixes represent the industry standard composite barrel for the respective periods presented and do not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

Oil prices in 2023 decreased compared with 2022 and increased compared with 2021. Gas and NGL prices in 2023 decreased compared with both 2022 and 2021. Given the uncertainty surrounding global financial markets, production output from OPEC+, global shipping channel constraints and disruptions, instability in the Middle East, economic and trade sanctions associated with the wars between Russia and Ukraine and Israel and Hamas, changes in oil inventory in storage, and the potential impacts of these issues on global commodity and financial markets, we expect benchmark prices for oil, gas, and NGLs to remain volatile for the foreseeable future, and we cannot reasonably predict the timing or likelihood of any future impacts that may result, which could include further inflation, supply chain disruptions, fluctuations in interest rates, and industry-specific impacts. In addition to supply and demand fundamentals, as global commodities, the prices for oil, gas, and NGLs are affected by real or perceived geopolitical risks in various regions of the world as well as the relative strength of the United States dollar compared to other currencies. Our realized prices at local sales points may also be affected by infrastructure capacity in the areas of our operations and beyond.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs as of February 8, 2024, and December 31, 2023:

	As of February 8, 2024	As of December 31, 2023
NYMEX WTI oil (per Bbl)	\$ 74.58	\$ 71.53
NYMEX Henry Hub gas (per MMBtu)	\$ 2.63	\$ 2.67
OPIS NGLs (per Bbl)	\$ 28.29	\$ 25.77

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives, and decisions regarding entering into commodity derivative contracts are overseen by a financial risk management committee consisting of certain senior executive officers and finance personnel. We make

decisions about the amount of our expected production that we cover by derivatives based on the amount of debt on our balance sheet, the level of capital commitments and long-term obligations we have in place, and the terms and futures prices that are made available by our approved counterparties. With our current commodity derivative contracts, we believe we have partially reduced our exposure to volatility in commodity prices and basis differentials in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor below which we are insulated from further price decreases. Please refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report and to *Commodity Price Risk in Overview of Liquidity and Capital Resources* below for additional information regarding our oil, gas, and NGL derivatives.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended December 31, 2023, and the preceding three quarters:

	For the Three Months Ended			
	December 31, 2023	September 30, 2023	June 30, 2023	March 31, 2023
	(in millions)			
Production (MMBOE)	14.1	14.1	14.1	13.2
Oil, gas, and NGL production revenue	\$ 606.9	\$ 639.7	\$ 546.6	\$ 570.8
Oil, gas, and NGL production expense	\$ 137.3	\$ 138.3	\$ 145.6	\$ 142.3
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	\$ 189.1	\$ 189.4	\$ 157.8	\$ 154.2
Exploration	\$ 15.8	\$ 10.2	\$ 15.0	\$ 18.4
General and administrative	\$ 36.6	\$ 29.3	\$ 27.5	\$ 27.7
Net income	\$ 247.1	\$ 222.3	\$ 149.9	\$ 198.6

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	December 31, 2023	September 30, 2023	June 30, 2023	March 31, 2023
Average net daily equivalent production (MBOE per day)	153.5	153.7	154.4	146.4
Lease operating expense (per BOE)	\$ 5.31	\$ 5.08	\$ 4.98	\$ 5.16
Transportation costs (per BOE)	\$ 2.08	\$ 2.07	\$ 2.89	\$ 2.81
Production taxes as a percent of oil, gas, and NGL production revenue	4.6 %	4.3 %	4.3 %	4.7 %
Ad valorem tax expense (per BOE)	\$ 0.37	\$ 0.70	\$ 0.83	\$ 0.81
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	\$ 13.39	\$ 13.39	\$ 11.23	\$ 11.70
General and administrative (per BOE)	\$ 2.60	\$ 2.07	\$ 1.96	\$ 2.10

Note: Amounts may not calculate due to rounding.

Overview of Selected Production and Financial Information, Including Trends

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2023	2022	2021	2023/2022	2022/2021	2023/2022	2022/2021
Net production volumes: ⁽¹⁾							
Oil (MMBbl)	23.8	24.0	27.9	(0.2)	(4.0)	(1)%	(14)%
Gas (Bcf)	132.4	125.9	108.4	6.4	17.6	5 %	16 %
NGLs (MMBbl)	9.7	8.0	5.4	1.7	2.6	21 %	49 %
Equivalent (MMBOE)	55.5	53.0	51.4	2.5	1.6	5 %	3 %
Average net daily production: ⁽¹⁾							
Oil (MBbl per day)	65.1	65.7	76.5	(0.6)	(10.8)	(1)%	(14)%
Gas (MMcf per day)	362.7	345.0	296.9	17.6	48.1	5 %	16 %
NGLs (MBbl per day)	26.4	21.9	14.7	4.5	7.2	21 %	49 %
Equivalent (MBOE per day)	152.0	145.1	140.7	6.9	4.4	5 %	3 %
Oil, gas, and NGL production revenue (in millions): ⁽¹⁾							
Oil production revenue	\$ 1,813.8	\$ 2,270.1	\$ 1,891.8	\$ (456.3)	\$ 378.2	(20)%	20 %
Gas production revenue	327.9	790.9	525.5	(463.0)	265.4	(59)%	51 %
NGL production revenue	222.2	285.0	180.6	(62.7)	104.3	(22)%	58 %
Total oil, gas, and NGL production revenue	<u>\$ 2,363.9</u>	<u>\$ 3,345.9</u>	<u>\$ 2,597.9</u>	<u>\$ (982.0)</u>	<u>\$ 748.0</u>	(29)%	29 %
Oil, gas, and NGL production expense (in millions): ⁽¹⁾							
Lease operating expense	\$ 284.8	\$ 266.5	\$ 225.5	\$ 18.3	\$ 41.0	7 %	18 %
Transportation costs	136.2	150.0	139.4	(13.8)	10.6	(9)%	8 %
Production taxes	105.1	162.6	121.1	(57.5)	41.5	(35)%	34 %
Ad valorem tax expense	37.4	41.7	19.4	(4.3)	22.3	(10)%	115 %
Total oil, gas, and NGL production expense	<u>\$ 563.5</u>	<u>\$ 620.9</u>	<u>\$ 505.4</u>	<u>\$ (57.4)</u>	<u>\$ 115.5</u>	(9)%	23 %
Realized price:							
Oil (per Bbl)	\$ 76.28	\$ 94.67	\$ 67.72	\$ (18.39)	\$ 26.95	(19)%	40 %
Gas (per Mcf)	\$ 2.48	\$ 6.28	\$ 4.85	\$ (3.80)	\$ 1.43	(61)%	29 %
NGLs (per Bbl)	\$ 23.02	\$ 35.66	\$ 33.67	\$ (12.64)	\$ 1.99	(35)%	6 %
Per BOE	\$ 42.60	\$ 63.18	\$ 50.58	\$ (20.58)	\$ 12.60	(33)%	25 %
Per BOE data: ⁽¹⁾							
Oil, gas, and NGL production expense:							
Lease operating expense	\$ 5.13	\$ 5.03	\$ 4.39	\$ 0.10	\$ 0.64	2 %	15 %
Transportation costs	2.46	2.83	2.71	(0.37)	0.12	(13)%	4 %
Production taxes	1.89	3.07	2.36	(1.18)	0.71	(38)%	30 %
Ad valorem tax expense	0.67	0.79	0.38	(0.12)	0.41	(15)%	108 %
Total oil, gas, and NGL production expense ⁽¹⁾	<u>\$ 10.16</u>	<u>\$ 11.72</u>	<u>\$ 9.84</u>	<u>\$ (1.56)</u>	<u>\$ 1.88</u>	(13)%	19 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	\$ 12.44	\$ 11.40	\$ 15.08	\$ 1.04	\$ (3.68)	9 %	(24)%
General and administrative	\$ 2.18	\$ 2.16	\$ 2.18	\$ 0.02	\$ (0.02)	1 %	(1)%
Net derivative settlement gain (loss) ⁽²⁾	\$ 0.49	\$ (13.42)	\$ (14.58)	\$ 13.91	\$ 1.16	104 %	8 %
Earnings per share information (in thousands, except per share data): ⁽³⁾							
Basic weighted-average common shares outstanding	118,678	122,351	119,043	(3,673)	3,308	(3)%	3 %
Diluted weighted-average common shares outstanding	119,240	124,084	123,690	(4,844)	394	(4)%	— %
Basic net income per common share	\$ 6.89	\$ 9.09	\$ 0.30	\$ (2.20)	\$ 8.79	(24)%	2,930 %
Diluted net income per common share	\$ 6.86	\$ 8.96	\$ 0.29	\$ (2.10)	\$ 8.67	(23)%	2,990 %

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- (1) Amounts and percentage changes may not calculate due to rounding.
 - (2) Net derivative settlements for the years ended December 31, 2023, 2022, and 2021, are included within the net derivative (gain) loss line item in the accompanying consolidated statements of operations (“accompanying statements of operations”).
 - (3) Please refer to *Note 9 – Earnings Per Share* in Part II, Item 8 of this report for additional discussion.

Average net daily equivalent production for the year ended December 31, 2023, increased five percent compared with 2022, as a result of an increased number of completions. In 2024, we expect total production volumes to increase slightly compared with 2023, and we expect a slight increase in oil as a percentage of total production. Please refer to *Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021* below for additional discussion.

We present certain information on a per BOE basis in order to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis and discussion.

Our realized price on a per BOE basis decreased \$20.58 for the year ended December 31, 2023, compared with 2022, as a result of decreases in oil, gas, and NGL benchmark prices. For the year ended December 31, 2023, we recognized a net gain on the settlement of our commodity derivative contracts of \$0.49 per BOE, compared to a net loss of \$13.42 per BOE for the same period in 2022.

LOE on a per BOE basis increased two percent for the year ended December 31, 2023, compared with 2022, primarily driven by increases in labor costs. For 2024, we expect LOE on a per BOE basis to increase, compared with 2023, primarily as a result of expected increases in certain operating costs associated with both our Midland Basin and South Texas assets. We anticipate volatility in LOE on a per BOE basis as a result of changes in total production, changes in our overall production mix, timing of workover projects, inflation, and industry activity, all of which affect total LOE.

Transportation costs on a per BOE basis decreased 13 percent for the year ended December 31, 2023, compared with 2022, as a result of the expiration of a long-term contract in South Texas on June 30, 2023. In general, we expect total transportation costs to fluctuate relative to changes in gas and NGL production from our South Texas assets, where we incur a majority of our transportation costs. For 2024, we expect transportation costs on a per BOE basis to decrease compared with 2023, as a result of the expiration of the long-term contract in South Texas previously discussed.

Production tax expense on a per BOE basis for the year ended December 31, 2023, decreased 38 percent compared with 2022, as a result of decreases in realized prices. Our overall production tax rate was 4.4 percent and 4.9 percent for the years ended December 31, 2023, and 2022, respectively. We generally expect production tax expense to correlate with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax expense that we recognize.

Ad valorem tax expense on a per BOE basis decreased 15 percent for the year ended December 31, 2023, compared with 2022, as we were positively impacted by a property tax relief bill that provided for a one-time benefit during 2023. We anticipate volatility in ad valorem tax expense on a per BOE and absolute basis as the valuation of our producing properties changes, which is generally driven by fluctuations in commodity prices, and can be impacted by changes in tax laws.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis increased nine percent for the year ended December 31, 2023, compared with 2022, due to inflation and higher drilling and completion activity in the Midland Basin, partially offset by increased production related to our South Texas assets, which have a lower DD&A rate than our Midland Basin assets. For 2024, we expect DD&A expense per BOE to remain flat, and DD&A expense on an absolute basis to increase slightly, compared with 2023, primarily as a result of expected increased production. Our DD&A rate fluctuates as a result of changes in our production mix, changes in our total estimated proved reserve volumes, changes in capital allocation, impairments, acquisition and divestiture activity, and carrying cost funding and sharing arrangements with third parties.

General and administrative (“G&A”) expense on a per BOE basis remained relatively flat for the year ended December 31, 2023, compared with 2022, as an increase in G&A expense on an absolute basis related to compensation expense was mostly offset by an increase in production volumes. Certain components of G&A expense, and G&A expense on a per BOE basis, are impacted by the Company’s full year performance against performance targets established at the beginning of the year and, therefore, are subject to variability. For 2024, we expect G&A expense per BOE to remain flat, and G&A expense on an absolute basis to increase compared with 2023, primarily as a result of expected increases in compensation expense due to inflation.

Please refer to *Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021* for additional discussion of operating expenses.

Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021

Please refer to *Comparison of Financial Results and Trends Between 2022 and 2021 and Between 2021 and 2020* in

Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2022 Annual Report on Form 10-K, filed with the SEC on February 23, 2023, for a detailed discussion of certain comparisons of our financial results and trends for the year ended December 31, 2022, compared with the year ended December 31, 2021.

Average net daily equivalent production, production revenue, and production expense

The following table presents the changes in our average net daily equivalent production, production revenue, and production expense, by area, between the years ended December 31, 2023, and 2022:

	Net Equivalent Production Increase (Decrease)		Production Revenue Decrease		Production Expense Decrease
	(MBOE per day)		(in millions)		(in millions)
Midland Basin	(6.0)	\$	(726.8)	\$	(44.3)
South Texas	13.0		(255.3)		(13.1)
Total	6.9	\$	(982.0)	\$	(57.4)

Note: Amounts may not calculate due to rounding.

Average net daily equivalent production volumes for the year ended December 31, 2023, increased five percent compared with 2022, comprised of a 20 percent increase from our South Texas assets, partially offset by a seven percent decrease from our Midland Basin assets. As a result of decreases in benchmark commodity prices, realized prices for oil, gas, and NGLs decreased 19 percent, 61 percent, and 35 percent, respectively, resulting in a 29 percent decrease in oil, gas, and NGL production revenue. Oil, gas, and NGL production expense for the year ended December 31, 2023, decreased nine percent, compared with 2022, primarily driven by decreases in production taxes and transportation costs, partially offset by an increase in LOE.

The following table presents the changes in our average net daily equivalent production, production revenue, and production expense, by area, between the years ended December 31, 2022, and 2021:

	Net Equivalent Production Increase (Decrease)		Production Revenue Increase		Production Expense Increase
	(MBOE per day)		(in millions)		(in millions)
Midland Basin	(13.0)	\$	222.0	\$	55.5
South Texas	17.3		526.0		60.0
Total	4.4	\$	748.0	\$	115.5

Note: Amounts may not calculate due to rounding.

Average net daily equivalent production volumes for the year ended December 31, 2022, increased three percent compared with 2021, comprised of a 37 percent increase from our South Texas assets, partially offset by a 14 percent decrease from our Midland Basin assets. As a result of increases in benchmark commodity prices, realized prices for oil, gas, and NGLs increased 40 percent, 29 percent, and six percent, respectively, resulting in a 29 percent increase in oil, gas, and NGL production revenue. Oil, gas, and NGL production expense for the year ended December 31, 2022, increased 23 percent, compared with 2021, primarily as a result of increased production taxes and LOE.

Please refer to *Overview of Selected Production and Financial Information, Including Trends* above for additional discussion, including discussion of trends on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	\$ 690.5	\$ 603.8	\$ 774.4

DD&A expense for the year ended December 31, 2023, increased 14 percent, compared with 2022, primarily as a result of inflation and a five percent increase in average net daily equivalent production volumes, partially offset by a shift in production mix due to higher activity in our South Texas assets, which have a lower DD&A rate than our Midland Basin assets. DD&A expense for the year

ended December 31, 2022, decreased 22 percent, compared with 2021, primarily as a result of increased estimated net proved reserves at the end of 2021 and during 2022, and increased activity in our Austin Chalk program. Please refer to *Overview of Selected Production and Financial Information, Including Trends* above for discussion of DD&A expense on a per BOE basis.

Exploration

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Geological, geophysical, and other expenses	\$ 26.4	\$ 24.7	\$ 7.0
Overhead	33.1	30.2	32.3
Total	\$ 59.5	\$ 54.9	\$ 39.3

Exploration expense increased eight percent for the year ended December 31, 2023, compared with 2022, primarily due to increases in both overhead and geological, geophysical, and other expenses. Exploration expense fluctuates based on actual geological and geophysical studies we perform within an exploratory area, exploratory dry hole expense incurred, and changes in the amount of allocated overhead.

Impairment

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Impairment	\$ —	\$ 7.5	\$ 35.0

No impairment expense was recorded for the year ended December 31, 2023, as a result of fewer actual and anticipated lease expirations and title defects. Impairment expense recorded during the years ended December 31, 2022, and 2021, consisted of unproved property abandonments and impairments related to actual and anticipated lease expirations, as well as actual and anticipated losses of acreage due to title defects, changes in development plans, and other inherent acreage risks.

We expect proved property impairments to occur more frequently in periods of declining or depressed commodity prices, and that the frequency of unproved property abandonments and impairments will fluctuate with the timing of lease expirations or title defects, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, unsuccessful exploration activities, and downward engineering revisions may result in proved and unproved property impairments.

Reserve estimates and related impairments of proved and unproved properties are difficult to predict in a volatile price environment. If commodity prices for the products we produce decline as a result of supply and demand fundamentals associated with geopolitical or macroeconomic events, we may experience proved and unproved property impairments in the future. Future impairments of proved and unproved properties are difficult to predict; however, based on our commodity price assumptions as of February 8, 2024, we do not expect any material oil and gas property impairments in the first quarter of 2024 resulting from commodity price impacts.

Please refer to *Critical Accounting Estimates* below and *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for additional discussion.

General and administrative

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
General and administrative	\$ 121.1	\$ 114.6	\$ 111.9

G&A expense increased six percent for the year ended December 31, 2023, compared with 2022, primarily as a result of increased compensation expense. Please refer to *Overview of Selected Production and Financial Information, Including Trends* above for discussion of G&A expense, including G&A expense on a per BOE basis.

Net derivative (gain) loss

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Net derivative (gain) loss	\$ (68.2)	\$ 374.0	\$ 901.7

Net derivative (gain) loss is a result of changes in fair values associated with fluctuations in the forward price curves for the commodities underlying our outstanding derivative contracts and the monthly cash settlements of our derivative positions during the period. We expect increases in benchmark commodity prices to result in net derivative losses, and decreases in benchmark commodity prices to result in net derivative gains, as measured against our derivative contract prices. Please refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Other operating expense, net

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Other operating expense, net	\$ 20.6	\$ 3.5	\$ 46.1

Other operating expense, net, recorded in 2023 and 2021, primarily related to legal matters.

Interest expense

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Interest expense	\$ (91.6)	\$ (120.3)	\$ (160.4)

Interest expense decreased 24 percent for the year ended December 31, 2023, compared with 2022, as a result of the reduction in the aggregate principal amount of our Senior Notes through various transactions in 2022, including the redemption of our 2024 Senior Notes on February 14, 2022, and the redemption of our 2025 Senior Secured Notes on June 17, 2022. Total interest expense can vary based on the timing and amount of borrowings under our revolving credit facility. Please refer to *Overview of Liquidity and Capital Resources* below, and to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion, including the definition of Senior Notes and 2025 Senior Secured Notes.

Interest income

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Interest income	\$ 19.9	\$ 5.8	\$ 1.7

Interest income increased for the year ended December 31, 2023, compared with 2022, due to an increase in average interest rates on our interest-bearing cash equivalents and a higher average cash and cash equivalents balance during 2023.

Loss on extinguishment of debt

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Loss on extinguishment of debt	\$ —	\$ (67.6)	\$ (2.1)

The redemption of our 2025 Senior Secured Notes during 2022 resulted in a net loss on extinguishment of debt of

\$67.2 million, which included \$33.5 million of premium paid, \$26.3 million of accelerated expense recognition of the unamortized debt discount, and \$7.4 million of accelerated expense recognition of the unamortized deferred financing costs. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion, including the definition of 2025 Senior Secured Notes.

Income tax expense

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions, except tax rate)		
Income tax expense	\$ (96.3)	\$ (283.8)	\$ (9.9)
Effective tax rate	10.5 %	20.3 %	21.5 %

Our effective tax rate decreased for the year ended December 31, 2023, compared with 2022, primarily due to benefits recognized as a result of a multi-year research and development (“R&D”) credit study conducted during 2023, partially offset by the release of the valuation allowance during the year ended December 31, 2023, that lowered the effective tax rate compared to no valuation benefit recognized during the year ended December 31, 2022.

The decrease in the effective tax rate for the year ended December 31, 2022, compared with 2021, primarily resulted from the release of the valuation allowance recorded against the derivative deferred tax asset recognized in prior periods. As a result of the increase in income before income taxes for the year ended December 31, 2022, compared with 2021, our permanent items, including excess tax benefits from stock-based compensation and limits on expensing of certain individual’s compensation, had less of an impact on the effective tax rate for the year ended December 31, 2022, compared with 2021.

During 2023, we made federal estimated tax payments of \$3.0 million and state cash tax payments of \$6.0 million, primarily related to Texas franchise taxes.

Enactment of proposed changes to federal income tax laws, specifically the Tax Relief for American Families and Workers Act of 2024, could have a material effect on our current tax expense, tax receivable, and deferred tax liabilities.

Please refer to *Critical Accounting Estimates* below and *Note 4 – Income Taxes* in Part II, Item 8 of this report for further discussion.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan while continuing to meet our current financial obligations. We continue to manage the duration and level of our drilling and completion service commitments in order to maintain flexibility with regard to our activity level and capital expenditures.

Sources of Cash

We expect our 2024 capital expenditure and return of capital programs to be funded with cash flows from operating activities and cash on hand. We may also use borrowings under our revolving credit facility or raise funds through new debt or equity offerings or from other sources of financing. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly issued securities may have rights, preferences, or privileges senior to those of existing stockholders and bondholders. Additionally, we may enter into carrying cost and sharing arrangements with third parties for certain exploration or development programs.

Our credit ratings affect the availability of, and cost for us to borrow, additional funds. Two major credit rating agencies upgraded our credit ratings during 2023, citing our ability to consistently generate meaningful cash flows, disciplined capital spending, return of capital to stockholders, debt redemptions during 2022, and sustained strong operational performance, including our established inventory of drilling locations in our Midland Basin and South Texas programs, all of which contribute to our strong liquidity profile.

All of our sources of liquidity can be affected by the general conditions of the broader economy, force majeure events, fluctuations in commodity prices, operating costs, interest rate changes, tax law changes, and volumes produced, all of which affect us and our industry.

We have no control over the market prices for oil, gas, and NGLs, although we may be able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of commodity derivative contracts as part of our commodity price risk management program. Commodity derivative contracts may limit the prices we receive for our oil, gas, and NGL sales if oil, gas, or NGL prices rise substantially over the price established by the commodity derivative contract. Please refer to *Note 7 – Derivative*

Financial Instruments in Part II, Item 8 of this report for additional information about our commodity derivative contracts currently in place and the timing of settlement of those contracts.

Credit Agreement

Our Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of \$3.0 billion. As of December 31, 2023, the borrowing base and aggregate lender commitments under our Credit Agreement were \$2.5 billion and \$1.25 billion, respectively. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both our proved oil and gas properties reflected in our most recent reserve report and commodity derivative contracts, each as determined by our lender group. The next scheduled borrowing base redetermination date is April 1, 2024. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. We must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring that we maintain certain financial ratios, as set forth in the Credit Agreement. We were in compliance with all financial and non-financial covenants as of December 31, 2023, and through the filing of this report. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion, as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Credit Agreement as of February 8, 2024, December 31, 2023, and December 31, 2022.

We had no revolving credit facility borrowings during the years ended December 31, 2023, and 2022. Cash flows provided by our operating activities, proceeds received from divestitures of properties, capital markets activities including open market debt repurchases, debt redemptions, repayment of scheduled debt maturities, other financing activities, and our capital expenditures, including acquisitions, all impact the amount we borrow under our revolving credit facility.

Weighted-Average Interest and Weighted-Average Borrowing Rates

Our weighted-average interest rate includes paid and accrued interest, fees on the unused portion of the aggregate commitment amount under the Credit Agreement, letter of credit fees, the non-cash amortization of deferred financing costs, and for the periods during which they were outstanding, the non-cash amortization of the discounts related to the 2021 Senior Secured Convertible Notes and 2025 Senior Secured Notes, each as defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. Our weighted-average borrowing rate includes paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2023, 2022, and 2021:

	For the Years Ended December 31,		
	2023	2022	2021
Weighted-average interest rate	7.1 %	7.6 %	7.7 %
Weighted-average borrowing rate	6.4 %	6.8 %	6.8 %

Our weighted-average interest rate and weighted-average borrowing rate both decreased for the year ended December 31, 2023, compared with 2022, as a result of the redemptions of our 2024 Senior Notes and 2025 Senior Secured Notes during 2022. Our weighted-average interest rate remained flat for the year ended December 31, 2022, compared with 2021, as an increase in deferred financing costs related to the Credit Agreement was offset by a decrease in interest expense resulting from the redemption of the 2025 Senior Secured Notes. Our weighted-average borrowing rate remained flat for the year ended December 31, 2022, compared with 2021, as a result of the timing of redemptions of our Senior Notes during 2022 and 2021.

Our weighted-average interest rate and weighted-average borrowing rate are affected by the occurrence and timing of long-term debt issuances and redemptions and the average outstanding balance on our revolving credit facility. Additionally, our weighted-average interest rate is affected by the fees paid on the unused portion of our aggregate lender commitments. The rates disclosed in the above table do not reflect certain amounts associated with the repurchase or redemption of Senior Notes, such as the accelerated expense recognition of the unamortized deferred financing costs and unamortized discounts, as these amounts are netted against the associated gain or loss on extinguishment of debt. The 2021 Senior Secured Convertible Notes were retired upon maturity on July 1, 2021, the 2024 Senior Notes were redeemed on February 14, 2022, and the 2025 Senior Secured Notes were redeemed on June 17, 2022. After these dates, the weighted-average interest rate was no longer affected by the non-cash amortization of deferred financing costs or, for the 2021 Senior Secured Convertible Notes and the 2025 Senior Secured Notes, the non-cash amortization of the discounts. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion and definitions.

Uses of Cash

We use cash for the development, exploration, and acquisition of oil and gas properties; for the payment of operating and general and administrative costs, income taxes, debt obligations, including interest and early repayments or redemptions, dividends, and for repurchases of shares of our outstanding common stock under the Stock Repurchase Program. Expenditures for the development, exploration, and acquisition of oil and gas properties are the primary use of our capital resources. During 2023, we spent

\$1.1 billion on capital expenditures and on acquisitions of proved and unproved oil and gas properties, including the acquisition of additional working interests in certain wells. This amount differs from the costs incurred amount of \$1.2 billion for the year ended December 31, 2023, as costs incurred is an accrual-based amount that also includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts. Please refer to *Costs Incurred in Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

The amount and allocation of our future capital expenditures will depend upon a number of factors, including our cash flows from operating, investing, and financing activities, our ability to execute our development program, inflation, and the number and size of acquisitions that we complete. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, tax law and other regulatory changes, and the timing and results of our exploration and development activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget and guidance to assess if changes are necessary based on current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

Changes to the Internal Revenue Code ("IRC"), could increase the corporate income tax rate and could eliminate or reduce current tax deductions for intangible drilling costs, depreciation of equipment costs, and other deductions which currently reduce our taxable income. Current and future legislation could reduce our net cash provided by operating activities over time, and could therefore result in a reduction of funding available for the items discussed above.

We may from time to time repurchase shares of our common stock, or repurchase or redeem all or portions of our outstanding debt securities, for cash, through exchanges for other securities, or a combination of both. Such repurchases or redemptions may be made in open market transactions, privately negotiated transactions, tender offers, pursuant to contractual provisions, or otherwise. Any such repurchases or redemptions will depend on our business strategy, prevailing market conditions, our liquidity requirements, contractual restrictions or covenants, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

During the years ended December 31, 2023, and 2022, we repurchased and subsequently retired 6.9 million shares and 1.4 million shares, respectively, of our common stock at a cost, excluding excise taxes, commissions, and fees, of \$228.0 million and \$57.2 million, respectively. As of the filing of this report, \$214.9 million remains available under the Stock Repurchase Program for repurchases of our common stock through December 31, 2024. Effective January 1, 2023, shares of common stock repurchased, net of shares of common stock issued, are subject to a one percent excise tax imposed by the IRA. We recorded an immaterial amount of excise tax related to common stock repurchases during 2023. Please refer to *Note 3 – Equity* in Part II, Item 8 of this report for discussion of the Stock Repurchase Program.

During the years ended December 31, 2023, 2022, and 2021, we paid \$71.6 million, \$19.6 million, and \$2.4 million, respectively, in dividends to our stockholders. Dividends paid reflects \$0.60, \$0.16, and \$0.02 per share during the years ended December 31, 2023, 2022, and 2021, respectively. During 2023, our Board of Directors approved a 20 percent increase to our fixed dividend to \$0.72 per share annually, to be paid in quarterly increments of \$0.18 per share, beginning in the first quarter of 2024. We currently intend to continue paying dividends to our stockholders for the foreseeable future, subject to our future earnings, our financial condition, covenants under our Credit Agreement and indentures governing each series of our outstanding Senior Notes, and other factors that could arise. The payment and amount of future dividends remain at the discretion of our Board of Directors.

During 2022, we redeemed all of the aggregate principal amount outstanding of our 2024 Senior Notes and our 2025 Senior Secured Notes. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion and definitions.

Analysis of Cash Flow Changes Between 2023 and 2022 and Between 2022 and 2021

The following tables present changes in cash flows between the years ended December 31, 2023, 2022, and 2021, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our accompanying consolidated statements of cash flows ("accompanying statements of cash flows") in Part II, Item 8 of this report.

Operating Activities

	For the Years Ended December 31,			Amount Change Between	
	2023	2022	2021	2023/2022	2022/2021
	(in millions)				
Net cash provided by operating activities	\$ 1,574.4	\$ 1,686.4	\$ 1,159.8	\$ (112.0)	\$ 526.6

Net cash provided by operating activities decreased for the year ended December 31, 2023, compared with 2022, primarily as a result of a \$937.3 million decrease in cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes and an increase of \$44.5 million in cash paid for LOE and ad valorem taxes, partially offset by a decrease of \$749.3 million in cash paid on settled derivative trades and a \$45.5 million decrease in cash paid for interest.

Net cash provided by operating activities increased for the year ended December 31, 2022, compared with 2021, primarily as a result of an \$833.2 million increase in cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, partially offset by an increase in cash paid for LOE and G&A expense of \$70.7 million and an increase of \$69.2 million in cash paid on settled derivative trades.

Net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements.

Investing Activities

	For the Years Ended December 31,			Amount Change Between	
	2023	2022	2021	2023/2022	2022/2021
	(in millions)				
Net cash used in investing activities	\$ (1,098.7)	\$ (880.3)	\$ (667.2)	\$ (218.4)	\$ (213.1)

Net cash used in investing activities increased for the year ended December 31, 2023, compared with 2022, as a result of a \$109.5 million increase in capital expenditures and \$109.9 million of cash paid to acquire proved and unproved oil and gas properties in the Midland Basin, including the acquisition of additional working interests in certain wells. Please refer to *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion of the acquisition of proved and unproved oil and gas properties.

Net cash used in investing activities increased for the year ended December 31, 2022, compared with 2021, primarily as a result of a \$205.1 million increase in capital expenditures.

Net cash used in investing activities during the years ended December 31, 2023, 2022, and 2021, was funded by net cash provided by operating activities.

Financing Activities

	For the Years Ended December 31,			Amount Change Between	
	2023	2022	2021	2023/2022	2022/2021
	(in millions)				
Net cash used in financing activities	\$ (304.5)	\$ (693.9)	\$ (159.8)	\$ 389.4	\$ (534.1)

Net cash used in financing activities during the year ended December 31, 2023, primarily consisted of \$228.1 million of cash paid, including commission and fees, to repurchase and subsequently retire 6.9 million shares of our common stock under the Stock Repurchase Program, and \$71.6 million of dividends paid to our stockholders.

Net cash used in financing activities during the year ended December 31, 2022, related to \$480.2 million of cash paid, including premium, to redeem our 2025 Senior Secured Notes, and \$104.8 million of cash paid to redeem our 2024 Senior Notes. Additionally, we paid \$57.2 million, including commission and fees, to repurchase and subsequently retire 1.4 million shares of our common stock under the Stock Repurchase Program, \$25.1 million for the net share settlement of employee stock awards, and \$19.6 million of dividends paid to our stockholders.

During the year ended December 31, 2021, we paid \$385.3 million, including net premiums, to fund the Tender Offer and the 2022 Senior Notes Redemption, and we received net cash proceeds of \$392.8 million from the issuance of our 2028 Senior Notes. Additionally, we paid \$65.5 million to retire our 2021 Senior Secured Convertible Notes and had net repayments under our revolving credit facility of \$93.0 million.

Please refer to *Note 3 – Equity* in Part II, Item 8 of this report for additional discussion of our Stock Repurchase Program and *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion and definitions related to our debt transactions.

Interest Rate Risk

We are exposed to market and credit risk due to the floating interest rate associated with any outstanding balance on our revolving credit facility. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the revolving credit facility's fair value but will not affect results of operations or cash flows. Conversely, for the portion of the revolving credit facility that has a floating interest rate, interest rate changes will not affect the fair value but will affect future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Notes, but can affect their fair

values. As of December 31, 2023, our outstanding principal amount of fixed-rate debt totaled \$1.6 billion, and we had no floating-rate debt outstanding. As we had no borrowings under our revolving credit facility during 2023, we had no exposure to variable interest rates during the year ended December 31, 2023. Please refer to *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for additional discussion on the fair values of our Senior Notes.

The Federal Reserve increased short-term interest rates during 2023 and 2022. These increases, and any future increases, are likely to increase the cost of and affect our ability to borrow funds.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly affect our revenue, profitability, access to capital, ability to return capital to our stockholders, and future rate of growth. Oil, gas, and NGL prices are subject to unpredictable fluctuations resulting from a variety of factors that are typically beyond our control, including changes in supply and demand associated with the broader macroeconomic environment, constraints on gathering systems, processing facilities, pipelines, and other transportation systems, and weather-related events. The markets for oil, gas, and NGLs have been volatile, especially over the last decade, and remain subject to high levels of uncertainty and volatility related to production output from OPEC+, global shipping channel constraints and disruptions, instability in the Middle East, economic and trade sanctions associated with the wars between Russia and Ukraine and Israel and Hamas, and the potential impacts of these issues on global commodity and financial markets. These circumstances have contributed to inflation, instances of supply chain disruptions, and a rise in interest rates, and could have further industry-specific impacts that may require us to adjust our business plan. The realized prices we receive for our production also depend on numerous factors that are typically beyond our control. Based on our 2023 production, a 10 percent decrease in our average realized prices for oil, gas, and NGLs, would have reduced our oil, gas, and NGL production revenues by approximately \$181.4 million, \$32.8 million, and \$22.2 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the year ended December 31, 2023, would have offset the declines in oil, gas, and NGL production revenue by approximately \$61.2 million.

We enter into commodity derivative contracts in order to reduce the risk of fluctuations in commodity prices. The fair value of our commodity derivative contracts is largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2023, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net derivative positions for these products by approximately \$30.0 million, \$5.2 million, and \$0.7 million, respectively.

Off-Balance Sheet Arrangements

We have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (“SPE” or “SPEs”). Please refer to *Off-Balance Sheet Arrangements* within *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report for additional discussion.

Critical Accounting Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with GAAP requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities as of the date of our consolidated financial statements. We base our assumptions and estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate as a result of changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report. We have outlined below, those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Successful Efforts Method of Accounting. GAAP provides two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method, and both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report.

Oil and Gas Reserve Quantities. Our estimated proved reserve quantities and future net cash flows are critical to understanding the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our consolidated financial statements, including the calculations of DD&A expense, impairment of proved and unproved oil and gas properties, and asset retirement obligations. Please refer to *Oil and Gas Producing Activities* in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report for additional discussion on our accounting policies impacted by estimated reserve quantities.

Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure of discounted future net cash flows calculation requires that a 10 percent discount rate be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We engage Ryder Scott, an independent reservoir evaluation consulting firm, to audit a minimum of 80 percent of our total calculated proved reserve PV-10. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year end. It should not be assumed that the standardized measure of discounted future net cash flows (GAAP) or PV-10 (non-GAAP) as of December 31, 2023, is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based these measures on the unweighted arithmetic average of the first-day-of-the-month price of each month within the trailing 12-month period ended December 31, 2023. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimates. Please refer to *Risk Factors* in Part I, Item 1A of this report for additional discussion.

If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, which would reduce future net income. Changes in DD&A rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2023	2022	2021
	MMBOE Change		
Revisions resulting from performance ⁽¹⁾	37.2	(11.1)	3.4
Removal of net proved undeveloped reserves no longer in our five-year development plan	(30.8)	(19.9)	(40.6)
Revisions resulting from price changes	(28.4)	9.5	37.2
Total	<u>(22.0)</u>	<u>(21.5)</u>	<u>—</u>

Note: Amounts may not calculate due to rounding.

⁽¹⁾ For the year ended December 31, 2023, performance revisions consisted of positive revisions of 65.3 MMBOE resulting from changes to decline curve estimates based on reservoir engineering analysis and negative revisions of 28.0 MMBOE related to well performance.

As previously noted, commodity prices are volatile and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes.

We cannot reasonably predict future commodity prices, although we believe that together, the below analyses provide reasonable information regarding the impact of changes in pricing and trends on total estimated net proved reserves. The following table reflects the estimated MMBOE change and percentage change to our total reported estimated proved reserve volumes from the described hypothetical changes:

	For the year ended December 31, 2023	
	MMBOE Change	Percentage Change
10 percent decrease in SEC pricing ⁽¹⁾	(14.3)	(2)%
Average NYMEX strip pricing as of fiscal year end ⁽²⁾	2.5	— %
10 percent decrease in net proved undeveloped reserves ⁽³⁾	(26.4)	(4)%

⁽¹⁾ The change solely reflects the impact of a 10 percent decrease in SEC pricing to the total reported estimated net proved reserve volumes as of December 31, 2023, and does not include additional impacts to our estimated net proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs.

⁽²⁾ The change solely reflects the impact of replacing SEC pricing with the five-year average NYMEX strip pricing as of December 31, 2023, and does not include additional impacts to our estimated net proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs. As of December 31, 2023, SEC pricing was \$78.22 per Bbl for oil, \$2.64 per MMBtu for gas, and \$27.72 per Bbl for NGLs, and five-year average NYMEX strip pricing was \$66.11 per Bbl for oil, \$3.53 per MMBtu for gas, and \$25.19 per Bbl for NGLs.

⁽³⁾ The change solely reflects a 10 percent decrease in net proved undeveloped reserves as of December 31, 2023, and does not include any additional impacts to our estimated net proved reserves.

Additional reserve information can be found in *Reserves* in Part I, Items 1 and 2 of this report, and in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Impairment of Oil and Gas Properties. Proved oil and gas properties are evaluated for impairment on a depletion pool-by-pool basis and reduced to fair value when events or changes in circumstances indicate that their carrying amount may not be recoverable. We estimate the expected future cash flows of our proved oil and gas properties and compare these undiscounted cash flows to the carrying amount to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the proved oil and gas properties to fair value (or discounted future cash flows). Management estimates future cash flows from all proved reserves and risk adjusted probable and possible reserves using various factors, which are subject to our judgment and expertise, and include, but are not limited to, commodity price forecasts, estimated future operating and capital costs, development plans, and discount rates to incorporate the risk and current market conditions associated with realizing the expected cash flows.

Unproved oil and gas properties are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by asset group and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and our intent to renew leases. We estimate the fair value of unproved properties using a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by us or other market participants.

We cannot predict when or if future impairment charges will be recorded because of the uncertainty in the factors discussed above. Despite any amount of future impairment being difficult to predict, based on our commodity price assumptions as of February 8, 2024, we do not expect any material oil and gas property impairments in the first quarter of 2024 resulting from commodity price impacts.

Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for discussion of impairments of oil and gas properties recorded for the years ended December 31, 2022, and 2021.

Revenue Recognition. We predominately derive our revenue from the sale of produced oil, gas, and NGLs. Our revenue recognition policy is a critical accounting estimate because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. A 10 percent change in our revenue accrual at year-end 2023 would have affected total operating revenues by approximately \$17.5 million for the year ended December 31, 2023. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 2 – Revenue from Contracts with Customers* in Part II, Item 8 of this report for additional discussion.

Derivative Financial Instruments. We periodically enter into commodity derivative contracts to mitigate a portion of our exposure to oil, gas, and NGL price volatility and location differentials. We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income

(loss). The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Income Taxes. We account for deferred income taxes, whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the consolidated financial statements and the tax basis of assets and liabilities, as measured using currently enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. We record deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period, as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement as well as significant enacted tax rate changes could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by approximately \$9.1 million for the year ended December 31, 2023. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 4 – Income Taxes* in Part II, Item 8 of this report for additional discussion.

Accounting Matters

Please refer to *Recently Issued Accounting Standards* in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report for information on new authoritative accounting guidance.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes, and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. For additional information about hydraulic fracturing and related environmental matters, please refer to *Risk Factors – Risks Related to Oil and Gas Operations and the Industry – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.*

Climate Change and Air Quality. In June 2013, President Obama announced a Climate Action Plan designed to further reduce GHG emissions and prepare the nation for the physical effects that may occur as a result of climate change. The Climate Action Plan targeted methane reductions from the oil and gas sector as part of a comprehensive interagency methane strategy. As part of the Climate Action Plan, on May 12, 2016, the EPA issued final regulations applicable to new, modified, or reconstructed sources that amended and expanded 2012 regulations for the oil and gas sector by, among other things, setting emission limits for volatile organic compounds (“VOCs” or “VOC”) and methane, a GHG, and added requirements for previously unregulated sources. The 2016 NSPS requires reduction of methane and VOCs from certain activities in oil and gas production, processing, transmission and storage and applies to facilities constructed, modified, or reconstructed after September 18, 2015. The regulation requires, among other things, GHG and VOC emission limits for certain equipment, such as centrifugal compressors and reciprocating compressors; semi-annual leak detection and repair for well sites and quarterly for boosting and garnering compressor stations and gas transmission compressor stations; control requirements and emission limits for pneumatic pumps; and additional requirements for control of GHGs and VOCs from well completions. On September 14, and 15, 2020, the EPA finalized amendments to the 2012 and 2016 NSPS that removed transmission and storage infrastructure from regulation of methane emissions and other VOCs, as well as removed methane control requirements. The portion of the 2020 amendments that removed the transmission and storage infrastructure from the regulations was disapproved by the Congressional Review Act in 2021. In November 2021, the EPA proposed to expand the requirements of the 2012 and 2016 NSPS and also include requirements for states to develop performance standards to control methane emissions from existing sources. In December 2022, the EPA issued a supplemental proposal to update, strengthen, and expand the 2021 proposed rules. The EPA finalized the rule in December 2023.

States are also required to comply with the NAAQS. The oil and gas sector is often subjected to additional controls when areas within states are not attaining the ozone NAAQS as the VOCs emitted by the oil and gas sector are a precursor to ozone formation. The ozone NAAQS was set at 70 parts per billion (“ppb”) in 2015. In 2023, the EPA announced its plan to perform a full and complete review of the ozone NAAQS and intends to release an integrated review plan in 2024. The results of this review could result in changes to the ozone NAAQS which, if lowered, may result in additional actions by states requiring further emission controls and associated costs. Oil and gas facilities operating in areas that are determined to be out of compliance with the 70 ppb requirement or a lowered ozone NAAQS may be subject to increased emission controls and associated costs of compliance.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and many of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, there have been international conventions and efforts to establish standards for the reduction of GHGs globally, including the Paris accords in December 2015. The conditions for entry into force of the Paris accords were met on October 5, 2016 and the Agreement went into force 30 days later on November 4, 2016. At the United Nations Climate Change Conference in Glasgow in 2021, the United States and the European Union announced the Global Methane Pledge that aims to reduce methane emissions by 30 percent compared with 2020 levels.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Judicial challenges to new regulatory measures are likely and we cannot predict the outcome of such challenges. New regulatory suspensions, revisions, or rescissions and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. Finally, scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere produce climate changes that likely have significant physical effects, such as increased frequency and severity of storms, droughts, floods, and other climatic events. Such effects could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of GHG emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration, and low carbon fuel standards, could benefit us in a variety of ways. For example, although federal regulation and climate change legislation could reduce the overall demand for the oil and gas that we produce, the relative demand for gas may increase because the burning of gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources such as wind or solar power become more prevalent, gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, gas may become a more attractive transportation fuel. For each of the years ended December 31, 2023, and 2022, approximately 40 percent of our production on a per BOE basis was gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and gas reservoirs, could also benefit us through the potential to obtain GHG emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we believe provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement as further described in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our revolving credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX, we would be in default, an event that would prevent us from borrowing under our revolving credit facility and would therefore materially limit a significant source of our liquidity. In addition, if we are in default under our revolving credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing each series of our outstanding Senior Notes, as defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report, would be entitled to exercise all of their remedies for default.

The following table provides reconciliations of our net income (GAAP) and net cash provided by operating activities (GAAP) to adjusted EBITDAX (non-GAAP) for the periods presented:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Net income (GAAP)	\$ 817,880	\$ 1,111,952	\$ 36,229
Interest expense	91,630	120,346	160,353
Interest income	(19,854)	(5,774)	(1,716)
Income tax expense	96,322	283,818	9,938
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	690,481	603,780	774,386
Exploration ⁽¹⁾	55,333	50,978	35,346
Impairment	—	7,468	35,000
Stock-based compensation expense	20,250	18,772	18,819
Net derivative (gain) loss	(68,154)	374,012	901,659
Net derivative settlement gain (loss)	26,921	(710,700)	(748,958)
Loss on extinguishment of debt	—	67,605	2,139
Other, net	1,497	(3,969)	2,223
Adjusted EBITDAX (non-GAAP)	1,712,306	1,918,288	1,225,418
Interest expense	(91,630)	(120,346)	(160,353)
Interest income	19,854	5,774	1,716
Income tax expense	(96,322)	(283,818)	(9,938)
Exploration ⁽¹⁾⁽²⁾	(46,467)	(36,810)	(35,346)
Amortization of debt discount and deferred financing costs	5,486	10,281	17,275
Deferred income taxes	88,256	269,057	9,565
Other, net	(12,538)	(3,957)	(5,976)
Net change in working capital	(4,551)	(72,063)	117,411
Net cash provided by operating activities (GAAP)	\$ 1,574,394	\$ 1,686,406	\$ 1,159,772

⁽¹⁾ Stock-based compensation expense is a component of the exploration expense and general and administrative expense line items on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration expense.

⁽²⁾ For the year ended December 31, 2023, amount excludes certain capital expenditures related to unsuccessful exploration activity for one well that experienced technical issues during the drilling phase. For the year ended December 31, 2022, amount excludes certain capital expenditures related to unsuccessful exploration efforts outside of our core areas of operation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this Item is provided under the captions *Interest Rate Risk* and *Commodity Price Risk* in Item 7 above, as well as under the section entitled *Summary of Oil, Gas, and NGL Derivative Contracts in Place* in Note 7 – *Derivative Financial Instruments* in Part II, Item 8 of this report and is incorporated herein by reference.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 22, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

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 is 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 the critical audit matter does not alter in any way our opinion on the consolidated 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.

Depletion, Depreciation and Amortization (“DD&A”) of Proved Oil and Gas Properties

Description of the Matter At December 31, 2023, the net book value of the Company’s proved oil and gas properties was \$4.6 billion, and depletion, depreciation, amortization, and asset retirement obligation liability accretion was \$690.5 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, capitalized costs of proved properties are depleted using the units-of-production method based on proved reserves, as estimated by the Company’s engineers. Proved reserve estimates are impacted by various inputs, including historical production, oil and gas price assumptions, and future operating and capital cost assumptions, among others, and requires the expertise of the Company’s engineers in evaluating and interpreting the relevant data. Because of the complexity involved in estimating oil and gas reserves, management used independent petroleum engineers to audit the estimates prepared by the Company’s engineers as of December 31, 2023.

Auditing the Company’s DD&A calculation is especially complex because of the use of the work of the Company’s engineers and the independent petroleum engineers and the evaluation of management’s determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company’s controls that address the risk of material misstatement relating to proved oil and gas reserves as an input to the DD&A expense calculations, including management’s controls over the completeness and accuracy of the financial data used in estimating proved oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company’s engineers responsible for the preparation of the reserve estimates and the independent petroleum engineers used to audit the estimates. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data used by the engineers, in estimating proved oil and gas reserves by agreeing significant inputs to source documentation, where available, on a sample basis, and we assessed the inputs for reasonableness based on our review of corroborative evidence and consideration of any contrary evidence. We also tested that the DD&A expense calculations, are based on appropriate proved oil and gas reserves amounts from the Company’s reserve report.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 2012.

Denver, Colorado

February 22, 2024

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 616,164	\$ 444,998
Accounts receivable	231,165	233,297
Derivative assets	56,442	48,677
Prepaid expenses and other	12,668	10,231
Total current assets	<u>916,439</u>	<u>737,203</u>
Property and equipment (successful efforts method):		
Proved oil and gas properties	11,477,358	10,258,368
Accumulated depletion, depreciation, and amortization	(6,830,253)	(6,188,147)
Unproved oil and gas properties, net of valuation allowance of \$35,362 and \$38,008, respectively	335,620	487,192
Wells in progress	358,080	287,267
Other property and equipment, net of accumulated depreciation of \$59,669 and \$56,512, respectively	35,615	38,099
Total property and equipment, net	<u>5,376,420</u>	<u>4,882,779</u>
Noncurrent assets:		
Derivative assets	8,672	24,465
Other noncurrent assets	78,454	71,592
Total noncurrent assets	<u>87,126</u>	<u>96,057</u>
Total assets	<u>\$ 6,379,985</u>	<u>\$ 5,716,039</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	\$ 611,598	\$ 532,289
Derivative liabilities	6,789	56,181
Other current liabilities	15,425	10,114
Total current liabilities	<u>633,812</u>	<u>598,584</u>
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net	1,575,334	1,572,210
Asset retirement obligations	118,774	108,233
Net deferred tax liabilities	369,903	280,811
Derivative liabilities	1,273	1,142
Other noncurrent liabilities	65,039	69,601
Total noncurrent liabilities	<u>2,130,323</u>	<u>2,031,997</u>
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, \$0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 115,745,393 and 121,931,676 shares, respectively	1,157	1,219
Additional paid-in capital	1,565,021	1,779,703
Retained earnings	2,052,279	1,308,558
Accumulated other comprehensive loss	(2,607)	(4,022)
Total stockholders' equity	<u>3,615,850</u>	<u>3,085,458</u>
Total liabilities and stockholders' equity	<u>\$ 6,379,985</u>	<u>\$ 5,716,039</u>

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	For the Years Ended December 31,		
	2023	2022	2021
Operating revenues and other income:			
Oil, gas, and NGL production revenue	\$ 2,363,889	\$ 3,345,906	\$ 2,597,915
Other operating income	9,997	12,741	24,979
Total operating revenues and other income	2,373,886	3,358,647	2,622,894
Operating expenses:			
Oil, gas, and NGL production expense	563,543	620,912	505,416
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	690,481	603,780	774,386
Exploration	59,480	54,943	39,296
Impairment	—	7,468	35,000
General and administrative	121,063	114,558	111,945
Net derivative (gain) loss	(68,154)	374,012	901,659
Other operating expense, net	20,567	3,493	46,069
Total operating expenses	1,386,980	1,779,166	2,413,771
Income from operations	986,906	1,579,481	209,123
Interest expense	(91,630)	(120,346)	(160,353)
Interest income	19,854	5,774	1,716
Loss on extinguishment of debt	—	(67,605)	(2,139)
Other non-operating expense	(928)	(1,534)	(2,180)
Income from before income taxes	914,202	1,395,770	46,167
Income tax expense	(96,322)	(283,818)	(9,938)
Net income	\$ 817,880	\$ 1,111,952	\$ 36,229
Basic weighted-average common shares outstanding	118,678	122,351	119,043
Diluted weighted-average common shares outstanding	119,240	124,084	123,690
Basic net income per common share	\$ 6.89	\$ 9.09	\$ 0.30
Diluted net income per common share	\$ 6.86	\$ 8.96	\$ 0.29

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	For the Years Ended December 31,		
	2023	2022	2021
Net income	\$ 817,880	\$ 1,111,952	\$ 36,229
Other comprehensive income, net of tax:			
Pension liability adjustment ⁽¹⁾	1,415	8,827	749
Total other comprehensive income, net of tax	1,415	8,827	749
Total comprehensive income	\$ 819,295	\$ 1,120,779	\$ 36,978

⁽¹⁾ Please refer to *Note 11 – Pension Benefits* for additional discussion of the pension liability adjustment.

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except share data and dividends per share)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
Balances, January 1, 2021	114,742,304	\$ 1,147	\$ 1,827,914	\$ 200,697	\$ (13,598)	\$ 2,016,160
Net income	—	—	—	36,229	—	36,229
Other comprehensive income	—	—	—	—	749	749
Net cash dividends declared, \$0.02 per share	—	—	—	(2,393)	—	(2,393)
Issuance of common stock under Employee Stock Purchase Plan	313,773	3	2,636	—	—	2,639
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	827,572	9	(9,081)	—	—	(9,072)
Stock-based compensation expense	60,510	1	18,818	—	—	18,819
Issuance of common stock through cashless exercise of Warrants	5,918,089	59	(59)	—	—	—
Balances, December 31, 2021	121,862,248	\$ 1,219	\$ 1,840,228	\$ 234,533	\$ (12,849)	\$ 2,063,131
Net income	—	—	—	1,111,952	—	1,111,952
Other comprehensive income	—	—	—	—	8,827	8,827
Net cash dividends declared, \$0.31 per share	—	—	—	(37,927)	—	(37,927)
Issuance of common stock under Employee Stock Purchase Plan	113,785	1	3,038	—	—	3,039
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	1,291,427	13	(25,142)	—	—	(25,129)
Stock-based compensation expense	29,471	—	18,772	—	—	18,772
Purchase of shares under Stock Repurchase Program	(1,365,255)	(14)	(57,193)	—	—	(57,207)
Balances, December 31, 2022	121,931,676	\$ 1,219	\$ 1,779,703	\$ 1,308,558	\$ (4,022)	\$ 3,085,458
Net income	—	—	—	817,880	—	817,880
Other comprehensive income	—	—	—	—	1,415	1,415
Net cash dividends declared, \$0.63 per share	—	—	—	(74,159)	—	(74,159)
Issuance of common stock under Employee Stock Purchase Plan	114,427	1	3,057	—	—	3,058
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	554,216	6	(7,888)	—	—	(7,882)
Stock-based compensation expense	56,872	1	20,249	—	—	20,250
Issuance of common stock through cashless exercise of Warrants	19,037	—	—	—	—	—
Purchase of shares under Stock Repurchase Program	(6,930,835)	(70)	(230,100)	—	—	(230,170)
Balances, December 31, 2023	115,745,393	\$ 1,157	\$ 1,565,021	\$ 2,052,279	\$ (2,607)	\$ 3,615,850

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31,		
	2023	2022	2021
Cash flows from operating activities:			
Net income	\$ 817,880	\$ 1,111,952	\$ 36,229
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	690,481	603,780	774,386
Impairment	—	7,468	35,000
Stock-based compensation expense	20,250	18,772	18,819
Net derivative (gain) loss	(68,154)	374,012	901,659
Net derivative settlement gain (loss)	26,921	(710,700)	(748,958)
Amortization of debt discount and deferred financing costs	5,486	10,281	17,275
Loss on extinguishment of debt	—	67,605	2,139
Deferred income taxes	88,256	269,057	9,565
Other, net	(2,175)	6,242	(3,753)
Changes in working capital:			
Accounts receivable	(10,191)	38,554	(101,047)
Prepaid expenses and other	(2,437)	(1,055)	220
Accounts payable and accrued expenses	8,077	(109,562)	218,238
Net cash provided by operating activities	1,574,394	1,686,406	1,159,772
Cash flows from investing activities:			
Capital expenditures	(989,411)	(879,934)	(674,841)
Acquisition of proved and unproved oil and gas properties	(109,931)	(7)	(3,321)
Other, net	657	(322)	10,927
Net cash used in investing activities	(1,098,685)	(880,263)	(667,235)
Cash flows from financing activities:			
Proceeds from revolving credit facility	—	—	1,832,500
Repayment of revolving credit facility	—	—	(1,925,500)
Net proceeds from Senior Notes	—	—	392,771
Cash paid to repurchase Senior Notes	—	(584,946)	(450,776)
Repurchase of common stock	(228,105)	(57,207)	—
Net proceeds from sale of common stock	3,058	3,039	2,639
Dividends paid	(71,614)	(19,637)	(2,393)
Net share settlement from issuance of stock awards	(7,882)	(25,129)	(9,072)
Other, net	—	(9,981)	—
Net cash used in financing activities	(304,543)	(693,861)	(159,831)
Net change in cash, cash equivalents, and restricted cash	171,166	112,282	332,706
Cash, cash equivalents, and restricted cash at beginning of period	444,998	332,716	10
Cash, cash equivalents, and restricted cash at end of period	\$ 616,164	\$ 444,998	\$ 332,716
Supplemental schedule of additional cash flow information and non-cash activities:			
Operating activities:			
Cash paid for interest, net of capitalized interest	\$ (86,947)	\$ (134,240)	\$ (136,606)
Net cash paid for income taxes	\$ (8,975)	\$ (10,576)	\$ (864)
Investing activities:			
Changes in capital expenditure accruals	\$ 80,794	\$ 29,789	\$ (10,826)
Non-cash financing activities ⁽¹⁾			

⁽¹⁾ Please refer to Note 5 – Long-Term Debt for discussion of the debt transactions completed during the years ended December 31, 2022, and 2021.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies

Description of Operations

SM Energy Company, together with its consolidated subsidiaries, is an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X. Intercompany accounts and transactions have been eliminated. In connection with the preparation of the accompanying consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of December 31, 2023, through the filing of this report. Additionally, certain prior period amounts have been reclassified to conform to current period presentation in the accompanying consolidated financial statements.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities as of 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. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of DD&A expense, impairment of proved and unproved oil and gas properties, and asset retirement obligations, each of which represents a significant component of the accompanying consolidated financial statements.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Accounts Receivable

The Company's accounts receivable primarily consist of receivables due from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company's oil, gas, and NGL receivables are collected within 30 to 90 days and the Company has had minimal bad debts. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. Please refer to *Note 13 – Accounts Receivable and Accounts Payable and Accrued Expenses* for additional disclosure.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is regularly reviewed.

The Company does not believe the loss of any single purchaser of its production would materially affect its operating results, as oil, gas, and NGLs are products with well-established markets and numerous purchasers in the Company's operating areas. The following major customers and entities under common control accounted for 10 percent or more of the Company's total oil, gas, and NGL production revenue for at least one of the periods presented:

	For the Years Ended December 31,		
	2023	2022	2021
Major customer #1	24 %	24 %	27 %
Major customer #2	11 %	7 %	9 %
Major customer #3	6 %	8 %	15 %
Group #1 of entities under common control	22 %	24 %	18 %

For its commodity derivative instruments, the Company's policy is to only enter into contracts with affiliates of the lenders under its Credit Agreement as its derivative counterparties, and each counterparty must have certain minimum investment grade senior unsecured debt ratings.

The Company maintains its primary bank accounts with a large, multinational bank that has branch locations in the Company's areas of operation. The Company's policy is to diversify its concentration of cash and cash equivalent investments among multiple institutions and investment products to limit the amount of credit exposure to any single institution or investment.

Oil and Gas Producing Activities

Proved properties. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method, property acquisition costs and development costs are capitalized when incurred. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities in the field, are depleted on an asset group basis (properties aggregated based on geographical and geological characteristics) using the units-of-production method based on estimated net proved developed oil and gas reserves. Similarly, proved leasehold costs are depleted on the same asset group basis; however, the units-of-production method is based on estimated total net proved oil and gas reserves. The computation of DD&A expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment.

Proved oil and gas property costs are evaluated for impairment on a depletion pool-by-pool basis and reduced to fair value when there is an indication that associated carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future cash flows to a single present value amount, to measure the fair value of proved properties using a discount rate, price and cost forecasts, and certain reserve risk-adjustment factors, as selected by the Company's management. The Company uses a discount rate that represents a current market-based weighted average cost of capital. The discount rate typically ranges from 10 percent to 15 percent. The prices for oil and gas are forecast based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecast using OPIS Mont Belvieu pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Certain undeveloped reserve estimates are also risk-adjusted given the risk to related projected cash flows due to performance and exploitation uncertainties.

The partial sale of a proved property within an existing field is accounted for as a normal retirement and no gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

Unproved properties. The unproved oil and gas properties line item on the accompanying consolidated balance sheets ("accompanying balance sheets") consists of the costs incurred to acquire unproved leases. Leasehold costs allocated to those leases, or partial leases that have associated proved reserves recorded, are reclassified to proved properties and depleted on an asset group basis using the units-of-production method based on estimated total proved oil and gas reserves. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by asset group and the portion of such costs estimated to be nonproductive prior to lease expiration are recognized as a valuation allowance and amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and the Company's intent to renew leases. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk-weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants.

For the sale of unproved properties where the original cost has been partially or fully amortized by providing a valuation allowance on an asset group basis, neither a gain nor loss is recognized unless the sales price exceeds the original cost of the property, in which case a gain shall be recognized in the accompanying statements of operations in the amount of such excess.

Exploratory. Exploratory geological and geophysical, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Under the successful efforts method of accounting for oil and gas properties, exploratory well costs are initially capitalized pending the determination of whether proved reserves have been discovered. If proved reserves are discovered, exploratory well costs will be capitalized as proved properties and will be accounted for following the successful efforts method of accounting described above. If proved reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in the cash flows from investing activities section as part of capital expenditures within the accompanying statements of cash flows.

Please refer to *Note 8 – Fair Value Measurements* for additional information.

Other Property and Equipment

Other property and equipment such as facilities, equipment inventory, office furniture and equipment, buildings, and computer hardware and software are recorded at cost. The Company capitalizes certain software costs incurred during the application development stage. The application development stage generally includes software design, configuration, testing, and installation activities. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using either the straight-line method over the estimated useful lives of the assets, which range from three to 30 years, or the unit of output method when appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the Company's accounts.

Facilities and equipment inventory costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. To measure the fair value of facilities and equipment inventory, the Company uses an income valuation technique or market approach depending on the quality of information available to support management's assumptions and the circumstances. For facilities, the valuation includes consideration of the proved and unproved assets supported by the facilities, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties, including facilities requiring decommissioning. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired, or a facility is constructed. The increase in carrying value is included in the proved oil and gas properties line item in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective long-lived assets. Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's plugging and abandonment liabilities range from 5.5 percent to 12 percent. In periods subsequent to initial measurement of the liability, the Company must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or economic life, changes in inflation factors, or the Company's credit-adjusted risk-free rate as market conditions warrant. Please refer to *Note 14 – Asset Retirement Obligations* for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2023, and 2022.

Derivative Financial Instruments

The Company periodically enters into commodity derivative instruments to mitigate a portion of its exposure to oil, gas, and NGL price volatility and location differentials for its expected future oil, gas, and NGL production, and the associated effect on cash flows. These instruments typically include commodity price swaps and collar arrangements, as well as, basis swaps and roll differential swaps. Commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company does not designate its commodity derivative contracts as hedging instruments. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its accompanying statements of operations as they occur. Gains and losses on net derivative settlements are included within the cash flows from operating activities section of the accompanying statements of cash flows. Please refer to *Note 7 – Derivative Financial Instruments* for additional discussion.

Revenue Recognition

The Company derives revenue predominately from the sale of produced oil, gas, and NGLs. Revenue is recognized at the point in time when custody and title ("control") of the product transfers to the purchaser, which may differ depending on the applicable contractual terms. Revenue accruals are recorded monthly and are based on estimated production delivered to a purchaser and the expected price to be received. The Company uses knowledge of its properties, contractual arrangements, historical performance, NYMEX, local spot market, and OPIS prices, and other factors as the basis of these estimates. Variances between estimates and the actual amounts received are recorded in the month payment is received. Please refer to *Note 2 – Revenue from Contracts with Customers* for additional discussion.

Stock-Based Compensation

At December 31, 2023, the Company had stock-based employee compensation plans that included RSUs and Performance Share Units (“PSU or “PSUs”) issued to employees, RSUs and restricted stock issued to non-employee directors, and an employee stock purchase plan available to eligible employees. The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance, which is based on the estimated fair value of these awards determined at the time of grant, and is included within the general and administrative and exploration expense line items in the accompanying statements of operations. For stock-based compensation awards containing non-market based performance conditions, the Company evaluates the probability of the number of shares that are expected to vest, and then adjusts the expense to reflect the number of shares expected to vest and the cumulative vesting period met to date. Further, the Company accounts for forfeitures of stock-based compensation awards as they occur. Please refer to *Note 10 – Compensation Plans* for additional discussion.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the accompanying consolidated financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis. The cumulative effect of enacted tax rate changes on the net balance of reported amounts of assets and liabilities is recognized in the period of enactment. The Company’s policy is to record interest related to income taxes in the interest expense line item in the accompanying statements of operations, and to record penalties related to income taxes in the other non-operating expense line item in the accompanying statements of operations. Please refer to *Note 4 – Income Taxes* for additional discussion.

Earnings per Share

The Company uses the treasury stock method to determine the effect of potentially dilutive instruments. Please refer to *Note 9 – Earnings Per Share* for additional discussion.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that, under GAAP, are reported as separate components of stockholders’ equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of comprehensive income. The Company’s policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach. Please refer to *Note 11 – Pension Benefits* for detail on the changes in the balances of components comprising other comprehensive income.

Fair Value of Financial Instruments

The Company’s financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The Company’s Senior Notes, as defined in *Note 5 – Long-Term Debt*, are recorded at cost, net of unamortized deferred financing costs, and their respective fair values are disclosed in *Note 8 – Fair Value Measurements*. Additionally, the Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Leases

The Company accounts for leases in accordance with ASC Topic 842, *Leases*, (“Topic 842”), which requires lessees to recognize operating and finance leases with terms greater than 12 months on the balance sheet. The Company evaluates a contractual arrangement at its inception to determine if it is a lease or contains an identifiable lease component. Certain leases may contain both lease and non-lease components. The Company’s policy for all asset classes is to combine lease and non-lease components together and account for the arrangement as a single lease.

Certain assumptions and judgments made by the Company when evaluating a contract that meets the definition of a lease under Topic 842 include those to determine the discount rate and lease term. Unless implicitly defined, the Company determines the present value of future lease payments using an estimated incremental borrowing rate based on a yield curve analysis that factors in certain assumptions, including the term of the lease and credit rating of the Company at lease inception. The Company evaluates each contract containing a lease arrangement at inception to determine the length of the lease term when recognizing a right-of-use (“ROU”) asset and corresponding lease liability. When determining the lease term, options available to extend or early terminate the arrangement are evaluated and included when it is reasonably certain an option will be exercised. Exercising an early termination

option may result in an early termination penalty depending on the terms of the underlying agreement. The Company excludes from the balance sheet leases with terms that are less than one year.

An ROU asset represents a lessee's right to use an underlying asset for the lease term, while the associated lease liability represents the lessee's obligations to make lease payments. At the commencement date, which is the date on which a lessor makes an underlying asset available for use by a lessee, a lease ROU asset and corresponding lease liability is recognized based on the present value of the future lease payments. The initial measurement of lease payments may also be adjusted for certain items, including options that are reasonably certain to be exercised, such as options to purchase the asset at the end of the lease term, or options to extend or early terminate the lease. Excluded from the initial measurement of an ROU asset and corresponding lease liability are certain variable lease payments, such as payments made that vary depending on actual usage or performance.

Subsequent to initial measurement, costs associated with the Company's operating leases are either expensed or capitalized depending on how the underlying ROU asset is utilized and in accordance with GAAP requirements. When calculating the Company's ROU asset and liability for a contractual arrangement that qualifies as an operating lease, the Company considers all of the necessary payments made or that are expected to be made upon commencement of the lease. As discussed above, excluded from the initial measurement are certain variable lease payments, which for the Company's drilling rigs, completion crews, and midstream agreements, may be a significant component of the total lease costs. Please refer to *Note 12 – Leases* for additional discussion.

Industry Segment and Geographic Information

The Company operates in the exploration and production segment of the oil and gas industry, onshore in the United States. The Company reports as a single industry segment.

Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or SPEs, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that the Company is the primary beneficiary of a variable interest entity, that entity is consolidated into the Company's consolidated financial statements. The Company has not been involved in any unconsolidated SPE transactions during 2023 or 2022, or through the filing of this report.

Recently Issued Accounting Standards

In October 2023, the FASB issued ASU No. 2023-06, *Disclosure Improvements: Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative* ("ASU 2023-06"). ASU 2023-06 was issued to modify the disclosure or presentation requirements of a variety of topics in the codification. The effective date for each amendment will be the date on which the SEC's removal of the related disclosure from Regulation S-X or Regulation S-K becomes effective, with early adoption prohibited. The Company evaluated ASU 2023-06 and does not expect the adoption of the applicable amendments to have a material effect on its consolidated financial statements and related disclosures.

In November 2023, the FASB issued ASU No. 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures* ("ASU 2023-07"). ASU 2023-07 was issued to improve the disclosures about a public entity's reportable segments and to provide additional, more detailed information about a reportable segment's expenses. ASU 2023-07 is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The guidance is to be applied on a retrospective basis to all prior periods presented in the financial statements. The Company is within the scope of this ASU and is evaluating the impact of this ASU on its consolidated financial statement disclosures.

In December 2023, the FASB issued ASU No. 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* ("ASU 2023-09"). ASU 2023-09 was issued to improve the disclosures related to rate reconciliations and income taxes paid. ASU 2023-09 is effective for annual periods beginning after December 15, 2024, with early adoption permitted. The guidance should be applied on a prospective basis, however, retrospective application is permitted. The Company is within the scope of this ASU and is evaluating the impact of this ASU on its consolidated financial statement disclosures.

As of the filing of this report, the Company has not elected to early adopt ASU 2023-07 or ASU 2023-09.

As of December 31, 2023, and through the filing of this report, no other ASUs have been issued and not yet adopted that are applicable to the Company and that would have a material effect on the Company's consolidated financial statements and related disclosures.

Note 2 – Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs from its Midland Basin and South Texas assets. Oil, gas, and NGL production revenue presented within the accompanying statements of operations reflects revenue generated from contracts with customers.

The tables below present oil, gas, and NGL production revenue by product type for each of the Company's operating areas for the years ended December 31, 2023, 2022, and 2021:

	For the year ended December 31, 2023		
	Midland Basin	South Texas	Total
	(in thousands)		
Oil production revenue	\$ 1,347,780	\$ 465,995	\$ 1,813,775
Gas production revenue	175,183	152,700	327,883
NGL production revenue	687	221,544	222,231
Total	<u>\$ 1,523,650</u>	<u>\$ 840,239</u>	<u>\$ 2,363,889</u>
Relative percentage	64 %	36 %	100%

	For the year ended December 31, 2022		
	Midland Basin	South Texas	Total
	(in thousands)		
Oil production revenue	\$ 1,816,597	\$ 453,471	\$ 2,270,068
Gas production revenue	432,831	358,049	790,880
NGL production revenue	986	283,972	284,958
Total	<u>\$ 2,250,414</u>	<u>\$ 1,095,492</u>	<u>\$ 3,345,906</u>
Relative percentage	67 %	33 %	100%

	For the year ended December 31, 2021		
	Midland Basin	South Texas	Total
	(in thousands)		
Oil production revenue	\$ 1,701,915	\$ 189,911	\$ 1,891,826
Gas production revenue	326,115	199,364	525,479
NGL production revenue	381	180,229	180,610
Total	<u>\$ 2,028,411</u>	<u>\$ 569,504</u>	<u>\$ 2,597,915</u>
Relative percentage	78 %	22 %	100%

The Company recognizes oil, gas, and NGL production revenue at the point in time when control of the product transfers to the purchaser, which may differ depending on the applicable contractual terms. Transfer of control determines the presentation of transportation, gathering, processing, and other post-production expenses ("fees and other deductions") within the accompanying statements of operations. Fees and other deductions incurred by the Company prior to transfer of control are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations. When control is transferred at or near the wellhead, sales are based on a wellhead market price that may be affected by fees and other deductions incurred by the purchaser subsequent to the transfer of control. In general, the Company generates production revenue from a combination of the following types of contracts:

- The Company sells oil and gas production at or near the wellhead and receives an agreed-upon market price from the purchaser. Under this type of arrangement, control transfers at or near the wellhead.
- The Company has certain processing arrangements that include the delivery of unprocessed gas to a midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the NGLs and redelivers residue gas back to the Company in-kind. For the NGLs extracted during processing, the midstream processor remits payment to the Company. For the residue gas taken in-kind, the Company has separate sales contracts where control transfers at points downstream of the processing facility. The Company also has certain oil sales that occur at market locations downstream of the production area. Given the structure of these arrangements and where control transfers, the Company separately

recognizes fees and other deductions incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.

Significant judgments made in applying the guidance in ASC Topic 606, *Revenue from Contracts with Customers*, relate to the point in time when control transfers to purchasers in gas processing arrangements with midstream processors. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with generally predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied upon control transferring to a purchaser at the wellhead, inlet, or tailgate of the midstream processor's processing facility, or other contractually specified delivery point. The time period between production and satisfaction of performance obligations is generally less than one day; thus, there are no material unsatisfied or partially unsatisfied performance obligations at the end of the reporting period.

Revenue is recorded in the month when performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received 30 to 90 days after production has occurred. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the product. Estimated revenue due to the Company is recorded within the accounts receivable line item on the accompanying balance sheets until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of December 31, 2023, and 2022, were \$175.3 million and \$184.5 million, respectively. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser.

Note 3 – Equity

Stock Repurchase Program

During 2022, the Company's Board of Directors approved the Stock Repurchase Program authorizing the Company to repurchase up to \$500.0 million in aggregate value of its common stock through December 31, 2024. The Stock Repurchase Program permits the Company to repurchase shares of its common stock from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws and subject to certain provisions of the Credit Agreement and the indentures governing the Senior Notes, as defined in *Note 5 – Long-Term Debt*. The timing, as well as the number and value of shares repurchased under the Stock Repurchase Program, will be determined by certain authorized officers of the Company at their discretion and will depend on a variety of factors, including the market price of the Company's common stock, general market and economic conditions and applicable legal requirements. The value of shares authorized for repurchase by the Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of its shares will be repurchased by the Company.

The following table presents the Company's common stock repurchase activity for the years ended December 31, 2023, and 2022:

	For the Years Ended December 31,	
	2023	2022
	(in thousands, except per share data)	
Shares of common stock repurchased ⁽¹⁾	6,931	1,365
Weighted-average price per share ⁽²⁾	\$ 32.89	\$ 41.88
Cost of shares of common stock repurchased ^{(2) (3)}	\$ 227,966	\$ 57,179

⁽¹⁾ All repurchased shares of the Company's common stock were retired upon repurchase.

⁽²⁾ Amounts exclude excise taxes, commissions, and fees.

⁽³⁾ Amounts may not calculate due to rounding.

As of the filing of this report, \$214.9 million remains available for repurchases of the Company's outstanding common stock through December 31, 2024, under the Stock Repurchase Program.

Dividends

During 2023, the Company's Board of Directors approved an increase to the Company's fixed dividend to \$0.72 per share annually, to be paid in quarterly increments of \$0.18 per share, beginning in the first quarter of 2024. During the year ended December 31, 2023, net cash dividends declared totaled \$74.2 million.

Warrants

On June 17, 2020, the Company issued warrants to purchase up to an aggregate of approximately 5.9 million shares, or approximately five percent of its then outstanding common stock, at an exercise price of \$0.01 per share ("Warrants"). The Warrants became exercisable at the election of the holders on January 15, 2021, pursuant to the terms of the Warrant Agreement, dated June 17, 2020, and all of the Warrants were exercised prior to their expiration date of June 30, 2023.

The following table presents activity related to warrants exercised during the periods presented:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands, except per share data)		
Warrants exercised	19	—	5,922
Shares of common stock issued as a result of cashless exercise of warrants	19	—	5,918
Weighted-average share price on exercise date	\$ 29.09	\$ —	\$ 15.45

Note 4 – Income Taxes

The provision for income taxes consisted of the following:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Current portion of income tax (expense) benefit			
Federal	\$ (8,461)	\$ (9,230)	\$ —
State	395	(5,531)	(373)
Deferred portion of income tax expense	(88,256)	(269,057)	(9,565)
Income tax expense	<u>\$ (96,322)</u>	<u>\$ (283,818)</u>	<u>\$ (9,938)</u>
Effective tax rate	10.5 %	20.3 %	21.5 %

The components of the net deferred tax liabilities are as follows:

	As of December 31,	
	2023	2022
(in thousands)		
Deferred tax liabilities:		
Oil and gas properties excluding asset retirement obligation liabilities	\$ 450,634	\$ 358,537
Derivative assets	12,319	3,416
Other	6,283	6,059
Total deferred tax liabilities	469,236	368,012
Deferred tax assets:		
Credit carryover, net	56,097	161
Asset retirement obligation liabilities	26,592	24,899
Lease liabilities	4,454	4,525
Federal and state tax net operating loss carryovers	3,271	28,151
Legal liabilities	2,838	—
Pension	2,453	3,970
Interest carryforward	1,031	22,667
Other	4,003	4,444
Total deferred tax assets	100,739	88,817
Valuation allowance	(1,406)	(1,616)
Net deferred tax assets	99,333	87,201
Net deferred tax liabilities	\$ 369,903	\$ 280,811
Current federal income tax refundable (payable)	\$ (4,899)	\$ 770
Current state income tax refundable (payable)	\$ 1,253	\$ (5,316)

As of December 31, 2023, the Company had utilized all of its remaining federal net operating loss (“NOL”) carryovers and had gross state NOL carryforwards of \$74.0 million. Other than in states with no NOL carryforward expiration, the Company’s state NOL carryforwards expire between 2029 and 2039. The Company’s current valuation allowance includes an amount for state NOL carryforwards and state tax credits, which are expected to expire before they can be utilized.

The Company commissioned a multi-year R&D credit study in 2022, which was completed during 2023, and resulted in a favorable adjustment to the Company’s effective tax rate and a reduction of the Company’s 2022 and 2023 tax obligations. After utilizing a portion of the credits for the 2022 and 2023 tax years, the recorded net carryover R&D credit, as of December 31, 2023, expected to be utilized in future periods totaled \$56.1 million. The R&D credits expire between 2037 and 2043.

Income tax expense or benefit differs from the amount that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes. These differences primarily relate to the effect of federal tax credits, state income taxes, changes in valuation allowances, excess tax benefits and deficiencies from stock-based compensation awards, tax deduction limitations on compensation of covered individuals, the cumulative impact of other smaller permanent differences, and can also reflect the cumulative effect of an enacted tax rate change, in the period of enactment, on the Company's net deferred tax asset and liability balances. These differences for the years ended December 31, 2023, 2022, and 2021, are presented below:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Federal statutory tax expense	\$ (191,983)	\$ (293,112)	\$ (9,695)
(Increase) decrease in tax resulting from:			
Net federal R&D tax credit	92,420	—	—
Change in valuation allowance	210	16,845	(5,073)
State tax (expense) benefit, net of federal effect	5,166	(9,870)	(211)
Other	(2,135)	2,319	5,041
Income tax expense	<u>\$ (96,322)</u>	<u>\$ (283,818)</u>	<u>\$ (9,938)</u>

Acquisitions, divestitures, drilling activity, and basis differentials, which impact the prices received for oil, gas, and NGLs, impact the apportionment of taxable income to the states where the Company owns oil and gas properties. As these factors change, the Company's state income tax rate changes. This change, when applied to the Company's total temporary differences, impacts the total state income tax expense reported. Items affecting state apportionment factors are evaluated upon completion of the prior year income tax return, after significant acquisitions and divestitures, if there are significant changes in drilling activity, or if estimated state revenue changes occur during the year.

For all years before 2020, the Company is generally no longer subject to United States federal or state income tax examinations by tax authorities.

The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. The Company does not expect a significant change to the recorded unrecognized tax benefits in 2024, except for any potential changes related to the Company's R&D credit study discussed above and any potential 2024 R&D credit claims.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Beginning balance	\$ 446	\$ 446	\$ 446
Additions based on tax positions related to current year	23,713	—	—
Ending balance	<u>\$ 24,159</u>	<u>\$ 446</u>	<u>\$ 446</u>

Note 5 – Long-Term Debt

Credit Agreement

The Company's Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of \$3.0 billion. As of December 31, 2023, the borrowing base and aggregate lender commitments under the Credit Agreement were \$2.5 billion and \$1.25 billion, respectively. The revolving credit facility is secured by substantially all of the Company's proved oil and gas properties. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both the Company's proved oil and gas properties reflected in the Company's most recent reserve report; and commodity derivative contracts, each as determined by the Company's lender group. The next scheduled borrowing base redetermination date is April 1, 2024. The Credit Agreement is scheduled to mature on the earlier of August 2, 2027 ("Stated Maturity Date"), or 91 days prior to the maturity date of any of the Company's outstanding Senior Notes, as defined below, to the extent that, on or before such date, the respective Senior Notes have not been repaid, exchanged, repurchased, refinanced, or otherwise redeemed in full, and, if refinanced or exchanged, with a scheduled maturity date that is not earlier than at least 180 days after the Stated Maturity Date. The financial covenants under the Credit Agreement are discussed under *Covenants* below.

Interest and commitment fees associated with the revolving credit facility are accrued based on a borrowing base utilization grid set forth in the Credit Agreement, as presented in the table below. At the Company's election, borrowings under the Credit Agreement may be in the form of SOFR, Alternate Base Rate ("ABR"), or Swingline loans. SOFR loans accrue interest at SOFR plus the applicable margin from the utilization grid, and ABR and Swingline loans accrue interest at a market-based floating rate, plus the applicable margin from the utilization grid. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount at rates from the utilization grid.

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
SOFR Loans	2.000%	2.250%	2.500%	2.750%	3.000%
ABR Loans or Swingline Loans	1.000%	1.250%	1.500%	1.750%	2.000%
Commitment Fee Rate	0.375%	0.375%	0.500%	0.500%	0.500%

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of February 8, 2024, December 31, 2023, and December 31, 2022:

	As of February 8, 2024	As of December 31, 2023	As of December 31, 2022
	(in thousands)		
Revolving credit facility ⁽¹⁾	\$ —	\$ —	\$ —
Letters of credit ⁽²⁾	2,500	2,500	6,000
Available borrowing capacity	1,247,500	1,247,500	1,244,000
Total aggregate lender commitment amount	<u>\$ 1,250,000</u>	<u>\$ 1,250,000</u>	<u>\$ 1,250,000</u>

⁽¹⁾ Unamortized deferred financing costs attributable to the revolving credit facility are presented as a component of the other noncurrent assets line item on the accompanying balance sheets and totaled \$8.5 million and \$10.8 million as of December 31, 2023, and 2022, respectively. These costs are being amortized over the term of the revolving credit facility on a straight-line basis.

⁽²⁾ Letters of credit outstanding reduce the amount available under the revolving credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes, net line item on the accompanying balance sheets as of December 31, 2023, and 2022, consisted of the following (collectively referred to as "Senior Notes"):

	As of December 31, 2023			As of December 31, 2022		
	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net
	(in thousands)					
5.625% Senior Notes due 2025	\$ 349,118	\$ 896	\$ 348,222	\$ 349,118	\$ 1,528	\$ 347,590
6.75% Senior Notes due 2026	419,235	1,868	417,367	419,235	2,569	416,666
6.625% Senior Notes due 2027	416,791	2,395	414,396	416,791	3,172	413,619
6.5% Senior Notes due 2028	400,000	4,651	395,349	400,000	5,665	394,335
Total	<u>\$ 1,585,144</u>	<u>\$ 9,810</u>	<u>\$ 1,575,334</u>	<u>\$ 1,585,144</u>	<u>\$ 12,934</u>	<u>\$ 1,572,210</u>

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices that may include a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes. Fees incurred upon issuance of each series of Senior Notes are being amortized as deferred financing costs over the life of the respective notes, unless earlier redeemed or retired, in which case amortization has been proportionately accelerated.

2025 Senior Notes. On May 21, 2015, the Company issued \$500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025, at par, which mature on June 1, 2025 ("2025 Senior Notes"). The Company received net proceeds of \$491.0 million after deducting fees of \$9.0 million.

2026 Senior Notes. On September 12, 2016, the Company issued \$500.0 million in aggregate principal amount of 6.75% Senior Notes due 2026, at par, which mature on September 15, 2026 (“2026 Senior Notes”). The Company received net proceeds of \$491.6 million after deducting fees of \$8.4 million.

2027 Senior Notes. On August 20, 2018, the Company issued \$500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027, at par, which mature on January 15, 2027 (“2027 Senior Notes”). The Company received net proceeds of \$492.1 million after deducting fees of \$7.9 million.

2028 Senior Notes. On June 23, 2021, the Company issued \$400.0 million in aggregate principal amount of 6.5% Senior Notes due 2028, at par, which mature on July 15, 2028 (“2028 Senior Notes”). The Company received net proceeds of \$392.8 million after deducting fees of \$7.2 million.

Senior Notes Activity

On February 14, 2022, the Company redeemed the \$104.8 million of aggregate principal amount outstanding of its 5.0% Senior Notes due 2024 (“2024 Senior Notes”), with cash on hand, pursuant to the terms of the indenture governing the 2024 Senior Notes which provided for a redemption price equal to 100 percent of the principal amount of the 2024 Senior Notes on the date of redemption, plus accrued and unpaid interest. Upon redemption, the Company accelerated the amortization of all remaining previously unamortized deferred financing costs. The Company canceled all redeemed 2024 Senior Notes upon settlement.

On June 23, 2021, the Company issued \$400.0 million in aggregate principal amount of its 2028 Senior Notes, as described above. The net proceeds of \$392.8 million were used to repurchase \$193.1 million and \$172.3 million of outstanding principal amount of the Company’s 6.125% Senior Notes due 2022 (“2022 Senior Notes”) and 2024 Senior Notes, respectively, through a cash tender offer (“Tender Offer”), and to redeem the remaining \$19.3 million of 2022 Senior Notes not repurchased as part of the Tender Offer (“2022 Senior Notes Redemption”). The Company paid total consideration, excluding accrued interest, of \$385.3 million, and recorded a net loss on extinguishment of debt of \$2.1 million for the year ended December 31, 2021, which included the accelerated expense recognition of \$1.5 million of the remaining unamortized deferred financing costs and \$0.6 million of net premiums. The Company canceled all repurchased and redeemed 2022 Senior Notes and 2024 Senior Notes upon settlement.

Senior Secured Notes Activity

On June 17, 2022, the Company redeemed all of the \$446.7 million of aggregate principal amount outstanding of its 10.0% Senior Secured Notes due 2025 (“2025 Senior Secured Notes”), with cash on hand, at a redemption price equal to 107.5 percent of the principal amount outstanding on the date of the redemption, plus accrued and unpaid interest. Upon redemption, the Company recorded a net loss on extinguishment of debt of \$67.2 million which included \$33.5 million of premium paid, \$26.3 million of accelerated expense recognition of the unamortized debt discount, and \$7.4 million of accelerated expense recognition of the remaining unamortized deferred financing costs. The Company canceled all redeemed 2025 Senior Secured Notes upon settlement.

On July 1, 2021, the 1.50% Senior Secured Convertible Notes (“2021 Senior Secured Convertible Notes”) matured, and on that day, the Company used borrowings under its revolving credit facility to retire, at par, the outstanding principal amount of \$65.5 million.

Covenants

The Company is subject to certain financial and non-financial covenants under the Credit Agreement and the indentures governing the Senior Notes that, among other terms, limit the Company’s ability to incur additional indebtedness, make restricted payments including dividends, sell assets, create liens that secure debt, enter into transactions with affiliates, make certain investments, or merge or consolidate with other entities. The financial covenants under the Credit Agreement require that the Company’s (a) total funded debt, as defined in the Credit Agreement, to 12-month trailing adjusted EBITDAX ratio cannot be greater than 3.50 to 1.00 on the last day of each fiscal quarter; and (b) adjusted current ratio, as defined in the Credit Agreement, cannot be less than 1.00 to 1.00 as of the last day of any fiscal quarter. The Company was in compliance with all covenants under the Credit Agreement and the indentures governing the Senior Notes as of December 31, 2023, and through the filing of this report.

Capitalized Interest

Capitalized interest costs for the years ended December 31, 2023, 2022, and 2021, totaled \$20.4 million, \$17.6 million, and \$15.0 million, respectively. The amount of interest the Company capitalizes generally fluctuates based on the amount borrowed, the Company’s capital program, and the timing and amount of costs associated with capital projects that are considered in progress. Capitalized interest costs are included in total costs incurred. Please refer to *Costs Incurred in Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional information.

Note 6 – Commitments and Contingencies

Commitments

As of December 31, 2023, the Company had entered into various types of agreements as discussed below. The following table presents the annual minimum payments related to these agreements for the next five years, and the total minimum payments thereafter as of December 31, 2023:

<u>For the Years Ending December 31,</u>	<u>Amount</u>
	(in thousands)
2024	\$ 74,992
2025	52,175
2026	28,133
2027	13,791
2028	12,461
Thereafter	14,655
Total	<u>\$ 196,207</u>

Drilling Rig Contracts. The Company has drilling rig contracts in place to facilitate its drilling plans. As of December 31, 2023, the Company's drilling rig commitments totaled \$19.1 million under contract terms extending through the third quarter of 2024. If all of these contracts were terminated as of December 31, 2023, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay \$12.3 million in early termination fees. Subsequent to December 31, 2023, the Company entered into a new drilling rig contract, and as of the filing of this report, the Company's drilling rig commitments totaled \$14.5 million under contract terms extending through the third quarter of 2024. If all of these contracts were terminated as of the filing of this report, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay \$8.9 million in early termination fees. No material expenses related to early termination or standby fees were incurred by the Company during the year ended December 31, 2023, and the Company does not expect to incur material penalties with regard to its drilling rig contracts during 2024.

Delivery Commitments. The Company has gathering, processing, transportation throughput, and delivery commitments with various third-parties that require delivery of a minimum amount of oil and produced water. As of December 31, 2023, the Company had commitments to deliver a minimum of 5 MMBbl of oil through July of 2026 and 11 MMBbl of produced water through June of 2027. The Company would be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments under certain agreements. As of December 31, 2023, if the Company failed to deliver any product, as applicable, the aggregate undiscounted deficiency payments would total approximately \$11.5 million. This amount does not include deficiency payment estimates associated with approximately 1 MMBbl of future oil delivery commitments where the Company cannot predict with accuracy the amount and timing of these payments, as such payments are dependent upon the price of oil in effect at the time of settlement. The Company expects to fulfill the delivery commitments from a combination of production from existing productive wells, future development of proved undeveloped reserves, and future development of resources not yet characterized as proved reserves. Under certain of the Company's commitments, if the Company is unable to deliver the minimum quantity from its production, it may deliver production acquired from third-parties to satisfy its minimum volume commitments. As of the filing of this report, the Company does not expect to incur material shortfalls with regard to these commitments.

Office Leases. The Company leases office space under various operating leases totaling \$33.3 million, including maintenance, with certain terms extending into 2033. Rent expense for the years ended December 31, 2023, 2022, and 2021, was \$2.5 million, \$3.5 million, and \$4.8 million, respectively.

Electrical Power Purchase Contracts. As of December 31, 2023, the Company had fixed price contracts for the purchase of electrical power through March of 2029 with a total remaining obligation of \$41.8 million.

Sand Purchase Commitment. As of December 31, 2023, the Company had a sand purchase agreement with a minimum commitment of \$46.8 million through March of 2026. As of December 31, 2023, if the Company failed to purchase the minimum amount required by the contract, it would be subject to penalties of up to \$10.0 million. As of the filing of this report, the Company does not expect to incur penalties with regard to this agreement.

Compression Service Contracts. As of December 31, 2023, the Company had compression service contracts with terms extending through 2027 for equipment being used in field operations with a total remaining obligation of \$19.5 million.

Miscellaneous Contracts and Leases. As of December 31, 2023, the Company had miscellaneous contracts and leases totaling \$24.2 million, primarily related to IT contracts, water purchase agreements, and vehicle leases, with terms extending through 2027.

Drilling and Completion Commitments. As of December 31, 2023, the Company had an agreement that includes minimum drilling and completion footage requirements on certain existing leases. If these minimum requirements are not satisfied by March 31, 2024, the Company will be required to pay liquidated damages based on the difference between the actual footage drilled and completed and the minimum requirements. As of December 31, 2023, the liquidated damages could range from zero to a maximum of \$8.3 million, with the maximum exposure assuming no additional development activity occurred prior to March 31, 2024. As of the filing of this report, the Company does not expect to incur material liquidated damages with regard to this agreement.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the anticipated results of any pending litigation and claims are not expected to have a material effect on the results of operations, the financial position, or the cash flows of the Company.

Note 7 – Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company regularly enters into commodity derivative contracts to mitigate a portion of its exposure to oil, gas, and NGL price volatility and location differentials, and the associated effect on cash flows. All commodity derivative contracts that the Company enters into are for other-than-trading purposes. The Company's commodity derivative contracts consist of price swap and collar arrangements for oil and gas production, and price swap arrangements for NGL production. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap price, the Company receives the difference between the index price and the agreed upon swap price. If the index price is higher than the swap price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index price and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The Company has entered into fixed price oil and gas basis swaps in order to mitigate exposure to adverse pricing differentials between certain industry benchmark prices and the actual physical pricing points where the Company's production is sold. As of December 31, 2023, the Company had basis swap contracts with fixed price differentials between:

- NYMEX WTI and Argus WTI Midland ("WTI Midland") for a portion of its Midland Basin oil production with sales contracts that settle at WTI Midland prices;
- NYMEX WTI and Argus WTI Houston Magellan East Houston Terminal ("WTI Houston MEH") for a portion of its South Texas oil production with sales contracts that settle at WTI Houston MEH prices;
- NYMEX HH and Inside FERC West Texas ("IF Waha") for a portion of its Midland Basin gas production with sales contracts that settle at IF Waha prices; and
- NYMEX HH and Inside FERC Houston Ship Channel ("IF HSC") for a portion of its South Texas gas production with sales contracts that settle at IF HSC prices.

The Company has also entered into oil swap contracts to fix the differential in pricing between the NYMEX calendar month average and the physical crude oil delivery month ("Roll Differential") in which the Company pays the periodic variable Roll Differential and receives a weighted-average fixed price differential. The weighted-average fixed price differential represents the amount of net addition (reduction) to delivery month prices for the notional volumes covered by the swap contracts.

As of December 31, 2023, the Company had commodity derivative contracts outstanding through the fourth quarter of 2025 as summarized in the table below:

	Contract Period				2025
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	
	2024	2024	2024	2024	
Oil Derivatives (volumes in MBbl and prices in \$ per Bbl):					
Swaps					
ICE Brent Volumes	910	—	—	—	—
Weighted-Average Contract Price	\$ 85.50	\$ —	\$ —	\$ —	\$ —
Collars					
NYMEX WTI Volumes	795	1,846	1,669	556	—
Weighted-Average Floor Price	\$ 68.21	\$ 67.46	\$ 68.93	\$ 72.86	\$ —
Weighted-Average Ceiling Price	\$ 82.37	\$ 85.53	\$ 84.00	\$ 79.83	\$ —
Basis Swaps					
WTI Midland-NYMEX WTI Volumes	1,199	1,193	1,235	1,230	1,807
Weighted-Average Contract Price	\$ 1.21	\$ 1.21	\$ 1.21	\$ 1.21	\$ 1.15
WTI Houston MEH-NYMEX WTI Volumes	256	293	332	309	729
Weighted-Average Contract Price	\$ 1.83	\$ 1.82	\$ 1.82	\$ 1.82	\$ 1.85
Roll Differential Swaps					
NYMEX WTI Volumes	1,415	1,792	1,964	1,877	—
Weighted-Average Contract Price	\$ 0.57	\$ 0.57	\$ 0.57	\$ 0.57	\$ —
Gas Derivatives (volumes in BBtu and prices in \$ per MMBtu):					
Swaps					
NYMEX HH Volumes	—	4,186	1,393	—	5,891
Weighted-Average Contract Price	\$ —	\$ 3.17	\$ 3.39	\$ —	\$ 4.20
Collars					
NYMEX HH Volumes	8,382	4,432	4,612	5,716	13,217
Weighted-Average Floor Price	\$ 3.57	\$ 3.69	\$ 3.68	\$ 3.48	\$ 3.44
Weighted-Average Ceiling Price	\$ 7.82	\$ 4.00	\$ 4.21	\$ 5.24	\$ 5.06
Basis Swaps					
IF Waha-NYMEX HH Volumes	5,089	5,285	5,344	5,240	20,501
Weighted-Average Contract Price	\$ (0.61)	\$ (1.09)	\$ (0.99)	\$ (0.73)	\$ (0.66)
IF HSC-NYMEX HH Volumes	4,957	3,310	3,426	5,750	—
Weighted-Average Contract Price	\$ (0.01)	\$ (0.34)	\$ (0.30)	\$ (0.38)	\$ —
NGL Derivatives (volumes in MBbl and prices in \$ per Bbl):					
Swaps					
OPIS Propane Mont Belvieu Non-TET Volumes	62	65	68	70	—
Weighted-Average Contract Price	\$ 28.56	\$ 28.56	\$ 28.56	\$ 28.56	\$ —

Commodity Derivative Contracts Entered Into Subsequent to December 31, 2023

Subsequent to December 31, 2023, and through the filing of this report, the Company entered into the following commodity derivative contracts:

	Contract Period					
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2025	2026
	2024	2024	2024	2024		
Oil Derivatives (volumes in MBbl and prices in \$ per Bbl):						
Swaps						
NYMEX WTI Volumes	—	—	—	344	—	—
Weighted-Average Contract Price	\$ —	\$ —	\$ —	\$ 71.00	\$ —	\$ —
Collars						
NYMEX WTI Volumes	—	—	335	344	—	—
Weighted-Average Floor Price	\$ —	\$ —	\$ 65.00	\$ 65.00	\$ —	\$ —
Weighted-Average Ceiling Price	\$ —	\$ —	\$ 78.61	\$ 76.45	\$ —	\$ —
Basis Swaps						
WTI Midland-NYMEX WTI Volumes	—	—	—	—	941	—
Weighted-Average Contract Price	\$ —	\$ —	\$ —	\$ —	\$ 1.15	\$ —
WTI Houston MEH-NYMEX WTI Volumes	—	—	—	—	684	816
Weighted-Average Contract Price	\$ —	\$ —	\$ —	\$ —	\$ 1.95	\$ 2.10
Gas Derivatives (volumes in BBtu and prices in \$ per MMBtu):						
Swaps						
NYMEX HH Volumes	—	—	1,530	—	—	—
Weighted-Average Contract Price	\$ —	\$ —	\$ 2.99	\$ —	\$ —	\$ —
Collars						
NYMEX HH Volumes	—	—	—	1,612	4,838	—
Weighted-Average Floor Price	\$ —	\$ —	\$ —	\$ 3.00	\$ 3.00	\$ —
Weighted-Average Ceiling Price	\$ —	\$ —	\$ —	\$ 4.02	\$ 4.22	\$ —
Basis Swaps						
IF HSC-NYMEX HH Volumes	—	—	—	—	946	—
Weighted-Average Contract Price	\$ —	\$ —	\$ —	\$ —	\$ 0.0025	\$ —
NGL Derivatives (volumes in MBbl and prices in \$ per Bbl):						
Swaps						
OPIS Propane Mont Belvieu Non-TET Volumes	254	322	336	364	396	—
Weighted-Average Contract Price	\$ 32.33	\$ 32.57	\$ 32.54	\$ 32.49	\$ 32.86	\$ —
OPIS Normal Butane Mont Belvieu Non-TET Volumes	28	44	46	49	45	—
Weighted-Average Contract Price	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ 39.48	\$ —
OPIS Isobutane Mont Belvieu Non-TET Volumes	15	24	25	28	25	—
Weighted-Average Contract Price	\$ 41.58	\$ 41.58	\$ 41.58	\$ 41.58	\$ 41.58	\$ —

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company does not designate its commodity derivative contracts as hedging instruments. The fair value of the commodity derivative contracts at December 31, 2023, and 2022, was a net asset of \$57.1 million and \$15.8 million, respectively.

The following table details the fair value of commodity derivative contracts recorded in the accompanying balance sheets, by category:

	<u>As of December 31, 2023</u>		<u>As of December 31, 2022</u>	
	(in thousands)			
Derivative assets:				
Current assets	\$	56,442	\$	48,677
Noncurrent assets		8,672		24,465
Total derivative assets	<u>\$</u>	<u>65,114</u>	<u>\$</u>	<u>73,142</u>
Derivative liabilities:				
Current liabilities	\$	6,789	\$	56,181
Noncurrent liabilities		1,273		1,142
Total derivative liabilities	<u>\$</u>	<u>8,062</u>	<u>\$</u>	<u>57,323</u>

Offsetting of Derivative Assets and Liabilities

As of December 31, 2023, and 2022, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts:

	<u>Derivative Assets as of</u>		<u>Derivative Liabilities as of</u>	
	<u>December 31,</u>	<u>December 31,</u>	<u>December 31,</u>	<u>December 31,</u>
	<u>2023</u>	<u>2022</u>	<u>2023</u>	<u>2022</u>
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	\$ 65,114	\$ 73,142	\$ (8,062)	\$ (57,323)
Amounts not offset in the accompanying balance sheets	(7,362)	(26,136)	7,362	26,136
Net amounts	<u>\$ 57,752</u>	<u>\$ 47,006</u>	<u>\$ (700)</u>	<u>\$ (31,187)</u>

The Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring such amounts in accumulated other comprehensive loss. The Company had no commodity derivative contracts designated as hedging instruments for the years ended December 31, 2023, 2022, and 2021. Please refer to *Note 8 – Fair Value Measurements* for more information regarding the Company's derivative instruments, including its valuation techniques.

The following table summarizes the commodity components of the net derivative settlement (gain) loss, and the net derivative (gain) loss line items presented within the accompanying statements of cash flows and the accompanying statements of operations, respectively:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Net derivative settlement (gain) loss:			
Oil contracts	\$ 26,873	\$ 514,641	\$ 523,245
Gas contracts	(49,156)	171,598	152,361
NGL contracts	(4,638)	24,461	73,352
Total net derivative settlement (gain) loss:	<u>\$ (26,921)</u>	<u>\$ 710,700</u>	<u>\$ 748,958</u>
Net derivative (gain) loss:			
Oil contracts	\$ (20,813)	\$ 284,863	\$ 650,959
Gas contracts	(42,713)	82,769	172,248
NGL contracts	(4,628)	6,380	78,452
Total net derivative (gain) loss:	<u>\$ (68,154)</u>	<u>\$ 374,012</u>	<u>\$ 901,659</u>

Credit Related Contingent Features

As of December 31, 2023, all of the Company's derivative counterparties were members of the Company's Credit Agreement lender group. The Company does not enter into derivative contracts with counterparties that are not part of the lender group. Under the Credit Agreement, the Company is required to provide mortgage liens on assets having a value equal to at least 85 percent of the total PV-9, as defined in the Credit Agreement, of the Company's proved oil and gas properties evaluated in the most recent reserve report. Collateral securing indebtedness under the Credit Agreement also secures the Company's derivative agreement obligations.

Note 8 – Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy:

	As of December 31, 2023			As of December 31, 2022		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Assets:						
Derivatives ⁽¹⁾	\$ —	\$ 65,114	\$ —	\$ —	\$ 73,142	\$ —
Liabilities:						
Derivatives ⁽¹⁾	\$ —	\$ 8,062	\$ —	\$ —	\$ 57,323	\$ —

⁽¹⁾ This represents a financial asset or liability that is measured at fair value on a recurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. Please refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on the Company's policies for determining fair value for the categories discussed below.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivative instruments. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The commodity derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any commodity derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current revolving credit facility margins, and any change in such margins since the last measurement date.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Please refer to *Note 7 – Derivative Financial Instruments* for more information regarding the Company's derivative instruments.

Oil and Gas Properties and Other Property and Equipment

The Company had no assets included in total property and equipment, net, measured at fair value as of December 31, 2023, or 2022.

No impairment expense was recorded for the year ended December 31, 2023. Impairment expense for the years ended December 31, 2022, and 2021, was \$7.5 million and \$35.0 million, respectively, and consisted of unproved property abandonments and impairments related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. The balances in the unproved oil and gas properties line item on the accompanying balance sheets as of December 31, 2023, and 2022, are recorded at carrying value. Please refer to *Note 1 – Summary of Significant Accounting Policies* for information on the Company's policies for determining fair value of its oil and gas producing properties and related impairment expense.

Long-Term Debt

The following table reflects the fair value of the Company's Senior Notes obligations measured using Level 1 inputs based on quoted secondary market trading prices. These notes were not presented at fair value on the accompanying balance sheets as of December 31, 2023, or 2022, as they were recorded at carrying value, net of any unamortized deferred financing costs. Please refer to *Note 5 – Long-Term Debt* for additional information.

	As of December 31,			
	2023		2022	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
5.625% Senior Notes due 2025	\$ 349,118	\$ 348,189	\$ 349,118	\$ 337,821
6.75% Senior Notes due 2026	\$ 419,235	\$ 420,660	\$ 419,235	\$ 409,484
6.625% Senior Notes due 2027	\$ 416,791	\$ 416,549	\$ 416,791	\$ 402,120
6.5% Senior Notes due 2028	\$ 400,000	\$ 401,372	\$ 400,000	\$ 384,520

Note 9 – Earnings Per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities.

For the years ended December 31, 2023, 2022, and 2021, potentially dilutive securities for this calculation consisted primarily of non-vested RSUs, contingent PSUs, and Warrants, all of which were measured using the treasury stock method. The Warrants became exercisable at the election of the holders on January 15, 2021, and all of the Warrants were exercised prior to their expiration date of June 30, 2023. The Warrants were included as potentially dilutive securities on an adjusted weighted-average basis for the portions of the years ended December 31, 2023, 2022, and 2021, during which they were outstanding but not yet exercised. Please refer to *Note 3 – Equity* for additional detail regarding the terms of the Warrants.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to *Note 10 – Compensation Plans* under the heading *Performance Share Units*.

The following table sets forth the calculations of basic and diluted net income per common share:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands, except per share data)		
Net income	\$ 817,880	\$ 1,111,952	\$ 36,229
Basic weighted-average common shares outstanding	118,678	122,351	119,043
Dilutive effect of non-vested RSUs, contingent PSUs, and other	553	1,714	2,582
Dilutive effect of Warrants	9	19	2,065
Diluted weighted-average common shares outstanding	119,240	124,084	123,690
Basic net income per common share	\$ 6.89	\$ 9.09	\$ 0.30
Diluted net income per common share	\$ 6.86	\$ 8.96	\$ 0.29

Note 10 – Compensation Plans

The Company may grant various types of both short-term and long-term incentive-based awards under its compensation plans, such as cash awards, performance-based cash awards, and equity awards to eligible employees. Additionally, the Company grants stock-based compensation to its Board of Directors, and provides an employee stock purchase plan and a 401(k) plan to eligible employees.

As of December 31, 2023, approximately 2.8 million shares of common stock were available for grant under the Equity Plan. The issuance of a direct share benefit, such as a share of common stock, a stock option, a restricted share, an RSU or a PSU, counts as one share against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as two shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier.

Performance Share Units

The Company has granted PSUs to eligible employees as part of its Equity Plan. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on certain criteria over a three-year performance period. PSUs generally vest on the third anniversary of the grant date or upon other triggering events as set forth in the Equity Plan. Employees who meet retirement eligibility criteria, as defined by the applicable grant agreement, on the grant date of a PSU award vest in pro-rata increments on a daily basis over the three-year performance period beginning at the grant date, and any non-vested portions of a PSU award will be forfeited if the employee leaves the Company.

The fair value of PSUs is measured at the grant date using a stochastic Monte Carlo simulation using geometric Brownian motion ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for each iteration. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the path the stock price may take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three-year vesting period, as well as the volatilities and dividend yields for each of the Company's peers.

For PSUs granted in 2023 and 2022, which the Company determined to be equity awards, settlement will be determined based on a combination of the following criteria measured over the three-year performance period: the Company's Total Shareholder Return ("TSR") relative to the TSR of certain peer companies, the Company's absolute TSR, free cash flow ("FCF") generation, and the achievement of certain ESG targets, in each case as defined by the award agreement. The relative and absolute TSR portions of the fair value of the PSUs granted in 2023 and 2022, were measured on the grant date using the GBM Model. The portion of the awards associated with FCF generation and ESG performance conditions assumes that target amounts will be met at the end of the performance period. As a portion of these awards depends on performance-based settlement criteria, compensation expense may be adjusted in future periods as the expected number of shares of the Company's common stock issued to settle the units increases or decreases based on the Company's expected FCF generation and achievement of certain ESG targets.

The Company initially records compensation expense associated with the issuance of PSUs based on the fair value of the awards as of the grant date and may adjust compensation expense in future periods as discussed above. Compensation expense for PSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for PSUs was \$2.8 million, \$2.6 million, and \$6.0 million for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, there was \$8.6 million of total unrecognized expense related to non-vested PSUs, which is being amortized through mid-2026.

The fair value of PSUs granted in 2023 and 2022 was \$7.7 million and \$7.4 million, respectively. The fair value of PSUs that vested during the years ended December 31, 2022, and 2021, was \$12.3 million and \$8.4 million, respectively.

A summary of activity is presented in the following table:

	For the Years Ended December 31,					
	2023		2022		2021	
	PSUs ⁽¹⁾	Weighted-Average Grant-Date Fair Value ⁽²⁾	PSUs ⁽¹⁾	Weighted-Average Grant-Date Fair Value ⁽²⁾	PSUs ⁽¹⁾	Weighted-Average Grant-Date Fair Value ⁽²⁾
Non-vested at beginning of year	273,258	\$ 26.67	464,483	\$ 12.80	830,464	\$ 17.52
Granted	256,633	\$ 29.93	276,010	\$ 26.67	—	\$ —
Vested	(15,950)	\$ 25.50	(461,387)	\$ 12.81	(352,395)	\$ 23.81
Forfeited	(44,509)	\$ 26.45	(5,848)	\$ 18.24	(13,586)	\$ 15.46
Non-vested at end of year	<u>469,432</u>	\$ 27.83	<u>273,258</u>	\$ 26.67	<u>464,483</u>	\$ 12.80

⁽¹⁾ The number of PSUs presented assumes a multiplier of one. The actual final number of shares of common stock to be issued at the end of the three-year performance period will range from zero to two times the number of PSUs awarded depending on the three-year performance multiplier.

⁽²⁾ Amounts represent price per unit.

A summary of the shares of common stock issued to settle PSUs is presented in the table below:

	For the Years Ended December 31,	
	2022	2021
Shares of common stock issued to settle PSUs ⁽¹⁾	1,004,410	347,742
Less: shares of common stock withheld for income and payroll taxes	(349,487)	(112,919)
Net shares of common stock issued	<u>654,923</u>	<u>234,823</u>
Multiplier earned	2.0	1.0

⁽¹⁾ During the year ended December 31, 2023, there were no shares of common stock issued to settle PSUs. During the years ended December 31, 2022, and 2021, the Company settled PSUs that were granted in 2019 and 2018, respectively. The Company and all eligible recipients in 2022 and 2021 mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings, as provided for in the Equity Plan and applicable award agreements.

Employee Restricted Stock Units

The Company has granted RSUs to eligible employees as part of its Equity Plan. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. RSUs generally vest in one-third increments on each anniversary of the applicable grant date over the applicable vesting period or upon other triggering events as set forth in the Equity Plan. Employees who meet retirement eligibility criteria, as defined by the applicable grant agreement, at the time an RSU award is granted generally vest in six-month increments over the applicable vesting period beginning at the grant date. Retirement eligible employees must stay with the Company through the entire six-month vesting period to receive that increment of vesting and any non-vested portions of an RSU award will be forfeited when the employee leaves the Company.

The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the grant date. The fair value of an RSU is equal to the closing price of the Company's common stock on the grant date. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for RSUs for the years ended December 31, 2023, 2022, and 2021, was \$14.8 million, \$13.5 million, and \$10.2 million, respectively. As of December 31, 2023, there was \$25.7 million of total unrecognized compensation expense related to non-vested RSUs, which is being amortized through mid-2026.

The fair value of RSUs granted to eligible employees in 2023, 2022 and 2021, was \$20.2 million, \$18.0 million, and \$17.0 million, respectively, and the fair value of RSUs that vested during the years ended December 31, 2023, 2022, and 2021, was \$13.5 million, \$11.2 million, and \$9.3 million, respectively.

A summary of activity is presented in the following table:

	For the Years Ended December 31,					
	2023		2022		2021	
	RSUs	Weighted-Average Grant-Date Fair Value ⁽¹⁾	RSUs	Weighted-Average Grant-Date Fair Value ⁽¹⁾	RSUs	Weighted-Average Grant-Date Fair Value ⁽¹⁾
Non-vested at beginning of year	1,375,052	\$ 22.42	1,841,237	\$ 13.79	2,097,860	\$ 8.83
Granted	630,474	\$ 32.03	526,776	\$ 34.08	666,052	\$ 25.52
Vested	(805,205)	\$ 16.75	(920,927)	\$ 12.17	(843,098)	\$ 11.00
Forfeited	(119,777)	\$ 29.26	(72,034)	\$ 18.24	(79,577)	\$ 10.64
Non-vested at end of year	<u>1,080,544</u>	<u>\$ 31.49</u>	<u>1,375,052</u>	<u>\$ 22.42</u>	<u>1,841,237</u>	<u>\$ 13.79</u>

⁽¹⁾ Amounts represent price per unit.

A summary of the shares of common stock issued to settle RSUs is presented in the table below:

	For the Years Ended December 31,		
	2023	2022	2021
Shares of common stock issued to settle RSUs ⁽¹⁾	803,449	920,927	843,098
Less: shares of common stock withheld for income and payroll taxes	(249,233)	(284,423)	(250,349)
Net shares of common stock issued	<u>554,216</u>	<u>636,504</u>	<u>592,749</u>

⁽¹⁾ During the years ended December 31, 2023, 2022, and 2021, the Company issued shares of common stock to settle RSUs that related to awards granted in previous years. The Company and a majority of eligible recipients in 2023, and all eligible recipients in 2022 and 2021, mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements.

Director Shares

In 2023, 2022, and 2021, the Company issued a total of 56,872, 29,471, and 60,510 shares, respectively, of its common stock to its non-employee directors under the Equity Plan. For the years ended December 31, 2023, 2022, and 2021, the Company recorded \$1.6 million, \$1.5 million, and \$1.2 million, respectively, of compensation expense related to director shares. All shares issued to non-employee directors fully vested on December 31 of the year granted.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation, subject to a maximum of 2,500 shares per offering period and a maximum of \$25,000 in value related to purchases for each calendar year. The purchase price of the common stock is 85 percent of the lower of the trading price of the common stock on either the first or last day of the six-month offering period. The ESPP is intended to qualify as an "employee stock purchase plan" under Section 423 of the IRC.

A total of 114,427, 113,785, and 313,773 shares were issued under the ESPP in 2023, 2022, and 2021, respectively. Total proceeds to the Company for the issuance of these shares was \$3.1 million, \$3.0 million, and \$2.6 million, for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, the Company had approximately 3.3 million shares of its common stock available for issuance under the ESPP. The Company records compensation expense associated with the ESPP based on the estimated fair value of the ESPP grants as of the beginning of the offering period, and the expense is recognized within general and administrative expense and exploration expense over the six-month offering period. Total compensation expense recorded for the ESPP for the years ended December 31, 2023, 2022, and 2021, was \$1.1 million, \$1.2 million, and \$1.4 million, respectively.

The fair value of ESPP grants is measured at the grant date using the Black-Scholes option-pricing model. Expected volatility is calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six-month vesting period.

The fair value of ESPP shares issued during the periods reported above were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2023	2022	2021
Risk free interest rate	5.1 %	1.2 %	0.8 %
Dividend yield	1.8 %	0.1 %	0.3 %
Volatility factor of the expected market price of the Company's common stock	53.6 %	69.1 %	106.1 %
Expected life (in years)	0.5	0.5	0.5

401(k) Plan

The Company has a defined contribution plan ("401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute a maximum of 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches either 100 percent or 150 percent of each employee's contributions, depending on pension plan eligibility, up to six percent of the employee's base salary and short-term incentive bonus, and may make additional contributions at its discretion. Please refer to *Note 11 – Pension Benefits* for additional discussion of pension benefits. The Company's matching contributions to the 401(k) Plan were \$5.7 million, \$5.5 million, and \$3.9 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Note 11 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering employees who met age and service requirements and began employment with the Company prior to January 1, 2016 ("Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees ("Nonqualified Pension Plan" and together with the Qualified Pension Plan, "Pension Plans"). The Company froze the Pension Plans to new participants, effective January 1, 2016. Employees participating in the Pension Plans prior to the plans being frozen continue to earn benefits.

Obligations and Funded Status for the Pension Plans

The Company recognizes the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of the Company's Pension Plans in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment within the other comprehensive income, net of tax, line item in the accompanying consolidated statements of comprehensive income. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation, but excludes the effects of assumed future salary increases.

The Company's measurement date for plan assets and obligations is December 31.

	For the Years Ended December 31,	
	2023	2022
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	\$ 65,161	\$ 75,760
Service cost	3,706	4,652
Interest cost	3,200	2,314
Actuarial (gain) loss	84	(15,567)
Benefits paid	(4,883)	(1,998)
Projected benefit obligation at end of year	<u>67,268</u>	<u>65,161</u>
Change in plan assets:		
Fair value of plan assets at beginning of year	36,414	35,941
Actual return on plan assets	4,161	(3,529)
Employer contribution	10,000	6,000
Benefits paid	(4,883)	(1,998)
Fair value of plan assets at end of year	<u>45,692</u>	<u>36,414</u>
Funded status at end of year	<u>\$ (21,576)</u>	<u>\$ (28,747)</u>

The Company's underfunded status for the Pension Plans as of December 31, 2023, and 2022, was \$21.6 million and \$28.7 million, respectively, and is recognized in the accompanying balance sheets within the other noncurrent liabilities line item. There are no plan assets in the Nonqualified Pension Plan.

Accumulated Benefit Obligation in Excess of Plan Assets for the Pension Plans

	As of December 31,	
	2023	2022
	(in thousands)	
Projected benefit obligation	<u>\$ 67,268</u>	<u>\$ 65,161</u>
Accumulated benefit obligation	\$ 55,557	\$ 55,712
Less: fair value of plan assets	(45,692)	(36,414)
Underfunded accumulated benefit obligation	<u>\$ 9,865</u>	<u>\$ 19,298</u>

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate of return on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of the unrecognized net gain or loss resulting from actual experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for the year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation and the market-related value of plan assets, then the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

The pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in the accumulated other comprehensive loss line item within the accompanying balance sheets as of December 31, 2023, and 2022, totaled \$3.3 million and \$5.1 million, respectively, and related to unrecognized actuarial losses.

The pension liability adjustments recognized in other comprehensive income during 2023, 2022, and 2021, were as follows:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Net actuarial gain (loss)	\$ 1,737	\$ 10,327	\$ (612)
Amortization of prior service cost	—	—	13
Amortization of net actuarial loss	68	931	1,240
Settlements	—	—	312
Total pension liability adjustment, pre-tax	1,805	11,258	953
Tax expense	(390)	(2,431)	(204)
Total pension liability adjustment, net	<u>\$ 1,415</u>	<u>\$ 8,827</u>	<u>\$ 749</u>

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	\$ 3,706	\$ 4,652	\$ 4,455
Interest cost	3,200	2,314	2,089
Expected return on plan assets that reduces periodic pension benefit cost	(2,340)	(1,711)	(1,474)
Amortization of prior service cost	—	—	13
Amortization of net actuarial loss	68	931	1,240
Net periodic benefit cost	4,634	6,186	6,323
Settlements	—	—	312
Total net benefit cost	<u>\$ 4,634</u>	<u>\$ 6,186</u>	<u>\$ 6,635</u>

Pension Plan Assumptions

The weighted-average assumptions used to measure the Company's projected benefit obligation are as follows:

	As of December 31,	
	2023	2022
Projected benefit obligation:		
Discount rate	5.0%	5.2%
Rate of compensation increase	3.5%	3.5%

The weighted-average assumptions used to measure the Company's net periodic benefit cost are as follows:

	For the Years Ended December 31,		
	2023	2022	2021
Net periodic benefit cost:			
Discount rate	5.2%	3.1%	2.9%
Expected return on plan assets ⁽¹⁾	6.3%	3.6%	4.4%
Rate of compensation increase	3.5%	4.8%	4.4%

⁽¹⁾ There is no assumed expected return on plan assets for the Nonqualified Pension Plan because there are no plan assets in the Nonqualified Pension Plan.

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy prohibits the direct investment of plan assets in the Company's securities. The Qualified Pension Plan's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting of expected returns for given levels of risk are applied.

The Qualified Pension Plan's investment portfolio contains a diversified blend of investments, which may reflect varying rates of return. The investments are further diversified within each asset classification. This portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations.

The weighted-average asset allocation of the Qualified Pension Plan is as follows:

Asset Category	Target	As of December 31,	
	2024	2023	2022
Equity securities	49.0 %	43.0 %	47.1 %
Fixed income securities	26.0 %	25.5 %	21.0 %
Other securities	25.0 %	31.5 %	31.9 %
Total	100.0 %	100.0 %	100.0 %

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in the plan. The assumption of the expected long-term rate of return on plan assets of the Qualified Pension Plan is based upon the target asset allocation and is determined using forward-looking assumptions in the context of historical returns and volatilities for each asset class, as well as correlations among asset classes. The Company evaluates the expected rate of return on plan assets assumption on an annual basis.

Pension Plan Assets

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2023, and 2022, utilizing the fair value hierarchy discussed in Note 8 – Fair Value Measurements are as follows:

	Actual Asset Allocation ⁽¹⁾	Total	Fair Value Measurements Using:		
			Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
(in thousands)					
As of December 31, 2023					
Equity securities:					
Domestic ⁽²⁾	20.3 %	\$ 9,280	\$ 6,097	\$ 3,183	\$ —
International ⁽³⁾	22.7 %	10,349	10,349	—	—
Total equity securities	43.0 %	19,629	16,446	3,183	—
Fixed income securities:					
Core fixed income ⁽⁴⁾	25.5 %	11,646	11,646	—	—
Floating rate corporate loans ⁽⁵⁾	— %	—	—	—	—
Total fixed income securities	25.5 %	11,646	11,646	—	—
Other securities:					
Real estate ⁽⁶⁾	4.6 %	2,116	—	—	2,116
Collective investment trusts ⁽⁷⁾	13.6 %	6,206	—	6,206	—
Hedge fund ⁽⁸⁾	13.3 %	6,095	1,498	—	4,597
Total other securities	31.5 %	14,417	1,498	6,206	6,713
Total investments	100.0 %	\$ 45,692	\$ 29,590	\$ 9,389	\$ 6,713
As of December 31, 2022					
Equity securities:					
Domestic ⁽²⁾	20.7 %	\$ 7,533	\$ 5,012	\$ 2,521	\$ —
International ⁽³⁾	26.4 %	9,594	9,594	—	—
Total equity securities	47.1 %	17,127	14,606	2,521	—
Fixed income securities:					
Core fixed income ⁽⁴⁾	14.3 %	5,220	5,220	—	—
Floating rate corporate loans ⁽⁵⁾	6.7 %	2,450	2,450	—	—
Total fixed income securities	21.0 %	7,670	7,670	—	—
Other securities:					
Real estate ⁽⁶⁾	6.8 %	2,476	—	—	2,476
Collective investment trusts ⁽⁷⁾	1.9 %	687	—	687	—
Hedge fund ⁽⁸⁾	23.2 %	8,454	4,133	—	4,321
Total other securities	31.9 %	11,617	4,133	687	6,797
Total investments	100.0 %	\$ 36,414	\$ 26,409	\$ 3,208	\$ 6,797

(1) Percentages may not calculate due to rounding.

(2) Level 1 equity securities consist of United States large and small capitalization companies, which are actively traded securities that can be sold on demand. Level 2 equity securities are investments in a collective investment fund that is valued at net asset value based on the value of the underlying investments and total units outstanding on a daily basis. The objective of these funds is to approximate the S&P 500 by investing in one or more collective investment funds.

(3) International equity securities consist of a well-diversified portfolio of holdings of mostly large issuers organized in developed countries with liquid markets, commingled with investments in equity securities of issuers located in emerging markets that are believed to have strong sustainable financial productivity at attractive valuations.

(4) The objective of core fixed income funds is to achieve value added from sector or issue selection by constructing a portfolio to approximate the investment results of the Barclay's Capital Aggregate Bond Index with a modest amount of variability in duration around the index.

- (5) Investments consist of floating rate bank loans. The interest rates on these loans are typically reset on a periodic basis to account for changes in the level of interest rates.
- (6) The investment objective of direct real estate is to provide current income with the potential for long-term capital appreciation. Ownership in real estate entails a long-term time horizon, periodic valuations, and potentially low liquidity.
- (7) Collective investment trusts invest in short-term investments and are valued at the net asset value of the collective investment trust. The net asset value, as provided by the trustee, is used as a practical expedient to estimate fair value. The net asset value is based on the fair value of the underlying investments held by the fund less its liabilities.
- (8) The hedge fund portfolio includes investments in actively traded global mutual funds that focus on alternative investments and a hedge fund of funds that invests both long and short using a variety of investment strategies.

The following is a summary of the changes in Level 3 plan assets (in thousands):

Balance at January 1, 2022	\$	6,195
Purchases		400
Realized gain on assets		259
Unrealized loss on assets		(57)
Disposition		—
Balance at December 31, 2022	\$	6,797
Purchases		—
Realized gain on assets		364
Unrealized loss on assets		(448)
Disposition		—
Balance at December 31, 2023	\$	6,713

Contributions

The Company contributed \$10.0 million, \$6.0 million, and \$6.6 million to the Pension Plans for the years ended December 31, 2023, 2022, and 2021, respectively. The Company expects to make a \$10.6 million contribution to the Pension Plans in 2024.

Benefit Payments

The Pension Plans made actual benefit payments of \$4.9 million, \$2.0 million, and \$6.3 million for the years ended December 31, 2023, 2022, and 2021, respectively. Expected benefit payments over the next 10 years are as follows:

For the Years Ending December 31,	Amount
	(in thousands)
2024	\$ 6,865
2025	\$ 4,455
2026	\$ 7,064
2027	\$ 5,026
2028	\$ 5,281
2029 through 2033	\$ 25,587

Note 12 – Leases

As of December 31, 2023, and 2022, the Company had operating leases for asset classes that include office space, office equipment, drilling rigs, midstream agreements, vehicles, and equipment rentals used in field operations. For operating leases recorded on the accompanying balance sheets, remaining lease terms range from less than one year to approximately nine years. Certain leases contain optional extension periods that allow for terms to be extended for up to an additional 10 years, however in order to maintain financial and operational flexibility, there are no available options to extend that the Company is reasonably certain it will exercise. An early termination option exists for certain leases, some of which allow the Company to terminate a lease within one year, however, there are no leases in which material early termination options are reasonably certain to be exercised by the Company. As of December 31, 2023, and 2022, the Company did not have any agreements in place that were classified as finance leases under Topic 842. As of December 31, 2023, and through the filing of this report, the Company has no material lease arrangements which are scheduled to commence in the future. Please refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on the Company's policies for lease determination and classification.

The following table reflects the components of the Company's total lease costs, whether capitalized or expensed, related to operating leases, including short-term leases, and variable lease payments made for both short-term and long-term leases for the years ended December 31, 2023, and 2022. This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.

	For the Years Ended December 31,	
	2023	2022
	(in thousands)	
Operating lease cost	\$ 15,625	\$ 10,174
Short-term lease cost ⁽¹⁾	251,628	175,098
Variable lease cost ⁽²⁾	11,838	7,085
Total lease cost	<u>\$ 279,091</u>	<u>\$ 192,357</u>

⁽¹⁾ Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than one year. This amount includes drilling and completion activities and field equipment rentals, most of which are contracted for 12 months or less. It is expected that this amount will fluctuate primarily with the number of drilling rigs and completion crews the Company is operating under short-term agreements.

⁽²⁾ Variable lease payments relate to the actual usage associated with drilling rigs, completion crews, and vehicles, and variable utility costs associated with the Company's leased office space. Fluctuations in variable lease payments are primarily driven by the number of drilling rigs and completion crews operating.

Cash paid for amounts included in the measurement of lease liabilities for the years ended December 31, 2023, and 2022, were as follows:

	For the Years Ended December 31,	
	2023	2022
	(in thousands)	
Operating cash flows related to operating leases	\$ 4,181	\$ 4,718
Investing cash flows related to operating leases	\$ 11,300	\$ 5,042

Maturities for the Company's operating lease liabilities included on the accompanying balance sheets as of December 31, 2023, were as follows:

	As of December 31, 2023
	(in thousands)
2024	\$ 17,208
2025	11,242
2026	4,793
2027	2,685
2028	2,054
Thereafter	6,906
Total Lease payments	<u>\$ 44,888</u>
Less: Imputed interest ⁽¹⁾	(5,110)
Total	<u>\$ 39,778</u>

⁽¹⁾ The weighted-average discount rate used to determine the operating lease liability as of December 31, 2023, was 6.2 percent.

The following table presents supplemental accompanying balance sheet information for operating leases as of December 31, 2023, and 2022:

	As of December 31,	
	2023	2022
	(in thousands, except discount rate and lease term)	
Balance sheet classifications of operating leases:		
Other noncurrent assets	\$ 32,264	\$ 26,368
Other current liabilities	\$ 15,425	\$ 10,114
Other noncurrent liabilities	\$ 24,352	\$ 23,621
ROU assets obtained in exchange for operating lease liabilities	\$ 19,341	\$ 16,186
Weighted-average discount rate	6.2%	5.8%
Weighted-average remaining lease term (years)	4	5

Note 13 – Accounts Receivable and Accounts Payable and Accrued Expenses

The components of accounts receivable are as follows:

	As of December 31,	
	2023	2022
	(in thousands)	
Oil, gas, and NGL production revenue	\$ 175,334	\$ 184,458
Amounts due from joint interest owners	46,289	45,997
Other	9,542	2,842
Total accounts receivable	<u>\$ 231,165</u>	<u>\$ 233,297</u>

The components of accounts payable and accrued expenses are as follows:

	As of December 31,	
	2023	2022
	(in thousands)	
Drilling and lease operating cost accruals	\$ 144,707	\$ 125,570
Trade accounts payable	107,315	43,898
Revenue and severance tax payable	186,663	182,744
Property taxes	43,406	43,066
Compensation	54,819	35,799
Net derivative settlements	1,129	22,745
Interest	35,976	35,992
Dividends payable	20,834	18,290
Other	16,749	24,185
Total accounts payable and accrued expenses	<u>\$ 611,598</u>	<u>\$ 532,289</u>

Note 14 – Asset Retirement Obligations

Please refer to *Asset Retirement Obligations* in Note 1 – *Summary of Significant Accounting Policies* for a discussion of the initial and subsequent measurements of asset retirement obligation liabilities and the significant assumptions used in the estimates.

The following is a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2023, and 2022:

	As of December 31,	
	2023	2022
	(in thousands)	
Beginning asset retirement obligations	\$ 115,313	\$ 101,424
Liabilities incurred ⁽¹⁾	4,062	2,086
Liabilities settled ⁽²⁾	(4,489)	(6,356)
Accretion expense	6,330	5,344
Revision to estimated cash flows	1,938	12,815
Ending asset retirement obligations ⁽³⁾	<u>\$ 123,154</u>	<u>\$ 115,313</u>

⁽¹⁾ Reflects liabilities incurred through drilling activities and acquisitions of drilled wells.

⁽²⁾ Reflects liabilities settled through plugging and abandonment activities and divestitures of properties.

⁽³⁾ Balances as of December 31, 2023, and 2022, included \$4.4 million and \$7.1 million, respectively, related to the Company's current asset retirement obligation liability, which is recorded in the accounts payable and accrued expenses line item on the accompanying balance sheets.

Note 15 – Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2023, 2022, and 2021. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Beginning balance	\$ 49,047	\$ 15,576	\$ 5,698
Additions to capitalized exploratory well costs pending the determination of net proved reserves	70,762	49,047	15,576
Reclassifications based on the determination of net proved reserves	(47,985)	(14,721)	(5,698)
Capitalized exploratory well costs charged to expense ⁽¹⁾	(455)	(855)	—
Ending balance	<u>\$ 71,369</u>	<u>\$ 49,047</u>	<u>\$ 15,576</u>

⁽¹⁾ For the year ended December 31, 2023, amount relates to one well that experienced technical issues during the drilling phase. For the year ended December 31, 2022, amount relates to unsuccessful exploration activity outside of the Company's core areas of operation.

As of December 31, 2023, there were no material exploratory well costs that were capitalized for more than one year.

Note 16 – Acquisitions

On June 30, 2023, the Company acquired approximately 20,000 net acres of oil and gas properties in Dawson and northern Martin counties, Texas. Under authoritative accounting guidance, this transaction was considered to be an asset acquisition. Therefore, the properties were recorded based on the total consideration paid after purchase price adjustments and the transaction costs were capitalized as a component of the cost of the assets acquired. During the third quarter of 2023, the Company acquired additional working interests in certain wells. Total consideration paid for these transactions, after purchase price adjustments, was \$109.9 million.

Additionally, during the year ended December 31, 2023, the Company completed a non-monetary asset exchange of proved properties in Upton County, Texas. This exchange was recorded at carryover basis with no gain or loss recognized.

Supplemental Oil and Gas Information (unaudited)

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Development costs ⁽¹⁾	\$ 931,803	\$ 810,520	\$ 583,527
Exploration costs	172,590	147,042	125,415
Acquisitions			
Proved properties	65,019	18	71
Unproved properties ⁽²⁾	65,570	4,153	9,036
Total, including asset retirement obligations ⁽³⁾⁽⁴⁾	<u>\$ 1,234,982</u>	<u>\$ 961,733</u>	<u>\$ 718,049</u>

⁽¹⁾ Includes facility costs of \$24.1 million, \$30.0 million, and \$18.2 million for the years ended December 31, 2023, 2022, and 2021, respectively.

⁽²⁾ Includes amounts related to leasing activity and acquiring surface rights outside of acquisitions of proved and unproved properties totaling \$18.1 million, \$4.2 million, and \$5.8 million for the years ended December 31, 2023, 2022, and 2021, respectively.

⁽³⁾ Includes amounts related to estimated asset retirement obligations of \$6.0 million, \$15.1 million, and \$12.8 million for the years ended December 31, 2023, 2022, and 2021, respectively.

⁽⁴⁾ Includes capitalized interest of \$20.4 million, \$17.6 million, and \$15.0 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and gas producing activities and SEC rules for oil and gas reporting of reserve estimation and disclosure.

Proved reserves are the estimated quantities of oil, gas, and NGLs 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, and under existing economic conditions, operating methods, and government regulations prior to 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. All of the Company's estimated net proved reserves are located in the United States.

The tables below present a summary of changes in the Company's estimated net proved reserves for each of the years ended December 31, 2023, 2022, and 2021. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the Company's total calculated proved reserve PV-10 for each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

For the Year Ended December 31, 2023

	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	205.8	1,402.9	97.8	537.4
Revisions of previous estimates ⁽¹⁾	38.7	194.2	20.8	91.9
Discoveries and extensions	8.9	69.1	10.5	30.9
Sales of reserves	(3.2)	(13.1)	—	(5.4)
Purchases of minerals in place	3.6	11.2	—	5.5
Production	(23.8)	(132.4)	(9.7)	(55.5)
End of year	<u>230.1</u>	<u>1,532.0</u>	<u>119.5</u>	<u>604.9</u>
Net proved developed reserves:				
Beginning of year	110.4	902.1	57.1	317.8
End of year	118.5	948.5	64.7	341.2
Net proved undeveloped reserves:				
Beginning of year	95.4	500.8	40.7	219.6
End of year	111.6	583.5	54.8	263.6

Note: Amounts may not calculate due to rounding.

⁽¹⁾ Revisions of previous estimates consist of:

- 113.9 MMBOE of infill reserves;
- 65.3 MMBOE of positive performance revisions resulting from changes to decline curve estimates based on reservoir engineering analysis;
- 28.0 MMBOE of negative performance revisions related to well performance;
- 30.8 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company's future development plans, and due to certain lease obligations; and
- 28.4 MMBOE of negative price revisions resulting primarily from decreases in gas and NGL prices.

Please refer to *Areas of Operation* in Part I, Items 1 and 2 of this report, and to *Oil and Gas Reserve Quantities* in *Critical Accounting Estimates* in Part II, Item 7 of this report for additional information.

For the Year Ended December 31, 2022

	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	199.5	1,243.5	85.2	492.0
Revisions of previous estimates ⁽¹⁾	23.7	248.2	16.7	81.7
Discoveries and extensions	6.6	37.2	3.9	16.7
Sales of reserves	—	—	—	—
Purchases of minerals in place	—	—	—	—
Production	(24.0)	(125.9)	(8.0)	(53.0)
End of year	<u>205.8</u>	<u>1,402.9</u>	<u>97.8</u>	<u>537.4</u>
Net proved developed reserves:				
Beginning of year	110.7	833.0	50.7	300.2
End of year	110.4	902.1	57.1	317.8
Net proved undeveloped reserves:				
Beginning of year	88.8	410.4	34.5	191.8
End of year	95.4	500.8	40.7	219.6

Note: Amounts may not calculate due to rounding.

⁽¹⁾ Revisions of previous estimates consist of:

- 103.2 MMBOE of infill reserves;
- 9.5 MMBOE of positive price revisions;
- 19.9 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company's future development plans; and
- 11.1 MMBOE of negative performance revisions.

For the Year Ended December 31, 2021

	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	172.7	1,052.0	56.6	404.6
Revisions of previous estimates ⁽¹⁾	35.7	158.9	12.2	74.4
Discoveries and extensions	19.3	141.4	21.9	64.7
Sales of reserves	(0.3)	(0.5)	(0.1)	(0.4)
Purchases of minerals in place	0.1	0.1	—	0.1
Production	(27.9)	(108.4)	(5.4)	(51.4)
End of year	<u>199.5</u>	<u>1,243.5</u>	<u>85.2</u>	<u>492.0</u>
Net proved developed reserves:				
Beginning of year	89.8	643.9	32.1	229.3
End of year	110.7	833.0	50.7	300.2
Net proved undeveloped reserves:				
Beginning of year	82.9	408.1	24.4	175.3
End of year	88.8	410.4	34.5	191.8

Note: Amounts may not calculate due to rounding.

⁽¹⁾ Revisions of previous estimates consist of:

- 74.4 MMBOE of infill reserves;
- 37.2 MMBOE and 3.4 MMBOE of positive price and performance revisions, respectively; and
- 40.6 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company's future development plans.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of discounted future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the estimated proved reserves in place at the end of the period using year end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities and estimated abandonment costs.

The assumptions used to compute the standardized measure of discounted future net cash flows are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value amount. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure of discounted future net cash flows computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure of discounted future net cash flows:

	For the Years Ended December 31,		
	2023	2022	2021
Oil (per Bbl)	\$ 77.96	\$ 95.02	\$ 66.21
Gas (per Mcf)	\$ 2.52	\$ 6.39	\$ 4.28
NGLs (per Bbl)	\$ 22.35	\$ 35.88	\$ 29.31

The following summary sets forth the Company's future net cash flows relating to proved oil, gas, and NGL reserves based on the standardized measure of discounted future net cash flows:

	As of December 31,		
	2023	2022	2021
	(in thousands)		
Future cash inflows	\$ 24,466,288	\$ 32,024,639	\$ 21,027,406
Future production costs	(7,894,043)	(7,672,906)	(5,498,098)
Future development costs	(2,997,545)	(2,949,871)	(1,591,550)
Future income taxes	(2,000,016)	(3,888,342)	(2,130,280)
Future net cash flows	11,574,684	17,513,520	11,807,478
10 percent annual discount	(5,294,535)	(7,551,454)	(4,844,871)
Standardized measure of discounted future net cash flows	\$ 6,280,149	\$ 9,962,066	\$ 6,962,607

The principal sources of changes in the standardized measure of discounted future net cash flows were:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands)		
Standardized measure of discounted future net cash flows, beginning of year	\$ 9,962,066	\$ 6,962,607	\$ 2,682,457
Sales of oil, gas, and NGLs produced, net of production costs	(1,800,346)	(2,724,994)	(2,092,499)
Net changes in prices and production costs	(5,649,606)	4,428,804	5,242,783
Extensions and discoveries, net of related costs	280,545	424,463	783,215
Sales of reserves in place	(83,850)	—	(4,361)
Purchase of reserves in place	151,263	—	1,565
Previously estimated development costs incurred during the period	772,602	423,527	426,120
Changes in estimated future development costs	99,974	(462,015)	(25,355)
Revisions of previous quantity estimates	537,502	1,327,530	1,015,539
Accretion of discount	1,215,452	815,862	268,246
Net change in income taxes	1,096,099	(996,437)	(1,196,013)
Changes in timing and other	(301,552)	(237,281)	(139,090)
Standardized measure of discounted future net cash flows, end of year	<u>\$ 6,280,149</u>	<u>\$ 9,962,066</u>	<u>\$ 6,962,607</u>

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including our Chief Executive Officer (Principal Executive Officer) and our Chief Financial Officer (Principal Financial Officer), as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and our Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting 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. The Company's internal control over financial reporting includes those policies and procedures that:

- (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- (ii) 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
- (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2023. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (2013 framework).

Based on management's assessment and those criteria, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2023.

The Company's independent registered public accounting firm has issued an attestation report on the Company's internal control over financial reporting. That report immediately follows this report.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company

Opinion on Internal Control Over Financial Reporting

We have audited SM Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, SM Energy Company and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and our report dated February 22, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible 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 Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

/s/ Ernst & Young LLP

Denver, Colorado

February 22, 2024

ITEM 9B. OTHER INFORMATION

As part of its regular, annual evaluation of peer compensation practices, the Compensation Committee of the Board of Directors determined that changes were necessary for the Change of Control Executive Severance Agreement for the Company's Senior Vice Presidents, Executive Vice Presidents, and CEO. The Board of Directors approved these recommended changes, and on February 21, 2024, the Company's Senior Vice Presidents, Executive Vice Presidents, and CEO each executed a new Change of Control Executive Severance Agreement, the template of which is filed as Exhibit 10.16 to this report.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

These disclosures are not applicable to the Company.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning the Company's Directors, Executive Officers, and corporate governance is incorporated by reference to the information provided under the captions "*Proposal 1 - Election of Directors*," "*Information about our Executive Officers*," and "*Corporate Governance*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

The information required by this Item concerning compliance with Section 16(a) of the Exchange Act is incorporated by reference to the information provided under the caption "*Security Ownership of Certain Beneficial Owners and Management*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions "*Executive Compensation Tables*" and "*Director Compensation*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption "*Security Ownership of Certain Beneficial Owners and Management*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

Securities Authorized for Issuance Under Equity Compensation Plans. The Company has equity compensation plans under which options and shares of the Company's common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. The Company's stockholders have approved these plans. Please refer to *Note 10 – Compensation Plans* in Part II, Item 8 of this report for further information about the material terms of the Company's equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under equity compensation plans as of December 31, 2023:

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	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Equity Incentive Compensation Plan ⁽¹⁾			
Restricted stock units ⁽²⁾	1,091,094	N/A	
Performance share units ^{(2) (3)}	485,382	N/A	
Total for Equity Incentive Compensation Plan	1,576,476	\$ —	2,808,286
Employee Stock Purchase Plan ⁽⁴⁾	—	—	3,310,680
Equity compensation plans not approved by security holders	—	—	—
Total for all plans	1,576,476	\$ —	6,118,966

⁽¹⁾ In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of the Company or any affiliate of the Company. The Company's Board of Directors approved amendments to the Equity Plan in 2009, 2010, 2013, 2016, and 2018 and each amended plan was approved by stockholders at the respective annual stockholders' meetings. The total number of shares of the Company's common stock underlying awards granted in 2023, 2022, and 2021 under the Equity Plan were 943,979, 832,257, and 726,562, respectively.

⁽²⁾ RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per unit fair value, which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per unit fair value for the outstanding RSUs and PSUs was \$31.40 and \$27.75, respectively. Please refer to *Note 10 – Compensation Plans* in Part II, Item 8 of this report for additional discussion.

⁽³⁾ The number of shares of common stock assumes a multiplier of one. The actual final number of shares of common stock to be issued will range from zero to two times the number of PSUs awarded depending on the three-year performance multiplier.

⁽⁴⁾ Under the ESPP, eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation, subject to certain limitations discussed in *Note 10 – Compensation Plans* in Part II, Item 8 of this report. The purchase price of the common stock is 85 percent of the lower of the trading price of the common stock on either the first or last day of the six-month offering period. The ESPP is intended to qualify under Section 423 of the IRC. The total number of shares of the Company's common stock issued in 2023, 2022, and 2021 under the ESPP were 114,427, 113,785, and 313,773, respectively.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the captions "*Certain Relationships and Related Transactions*" and "*Corporate Governance*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the captions "*Independent Registered Public Accounting Firm*" and "*Audit Committee Pre-approval Policy and Procedures*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

PART IV

ITEM 15. EXHIBITS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Consolidated Financial Statements and Financial Statement Schedules:

Report of Independent Registered Public Accounting Firm (PCAOB ID 42)	60
Consolidated Balance Sheets	62
Consolidated Statements of Operations	63
Consolidated Statements of Comprehensive Income	64
Consolidated Statements of Stockholders' Equity	65
Consolidated Statements of Cash Flows	66
Notes to Consolidated Financial Statements	67

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Certificate of Amendment of Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010, dated May 25, 2023 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on May 30, 2023, and incorporated herein by reference)
3.3	Amended and Restated By-Laws of SM Energy Company, effective as of February 21, 2017 (filed as Exhibit 3.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)
4.1	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.2	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.3	Base Indenture, dated as of May 21, 2015, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.4	Third Supplemental Indenture, dated September 12, 2016 by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on September 12, 2016, and incorporated herein by reference)
4.5	Fourth Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)
4.6	Fifth Supplemental Indenture, dated as of June 23, 2021, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on June 23, 2021, and incorporated herein by reference)
4.7*	Description of Securities
10.1	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.2	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.3	Seventh Amended and Restated Credit Agreement dated as of August 2, 2022, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022, and incorporated herein by reference)

- [10.4††](#) [Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 \(filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference\)](#)
- [10.5†](#) [Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 \(filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference\)](#)
- [10.6†](#) [Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011 \(filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference\)](#)
- [10.7†](#) [Amendment No. 2 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2012 \(filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference\)](#)
- [10.8†](#) [Amendment No. 3 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2016 \(filed as Exhibit 10.29 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2015, and incorporated herein by reference\)](#)
- [10.9+](#) [SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of December 31, 2010 \(filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference\)](#)
- [10.10†](#) [SM Energy Company Non-Qualified Deferred Compensation Plan as of March 10, 2014 \(filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 24, 2014, and incorporated herein by reference\)](#)
- [10.11†](#) [Cash Bonus Plan, As Amended and Restated as of February 1, 2014 \(filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2013, and incorporated herein by reference\)](#)
- [10.12†](#) [Section 162\(m\) Cash Bonus Plan, effective as of May 21, 2014 \(filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 28, 2014, and incorporated herein by reference\)](#)
- [10.13†](#) [SM Energy Company Employee Stock Purchase Plan, amended and restated effective as of April 5, 2021 \(filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 16, 2021, and incorporated herein by reference\)](#)
- [10.14†](#) [Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 \(filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference\)](#)
- [10.15*†](#) [Summary of Compensation Arrangements for Non-Employee Directors](#)
- [10.16*†](#) [Change of Control Executive Severance Agreement](#)
- [10.17†](#) [Change of Control Severance Agreement dated December 18, 2022 between Lehman E. Newton, III and SM Energy Company. \(filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 21, 2022, and incorporated herein by reference\)](#)
- [10.18†](#) [Change of Control Severance Agreement dated December 29, 2022 between David Copeland and SM Energy Company. \(filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 30, 2022, and incorporated herein by reference\)](#)
- [10.19†](#) [Non-Competition and Non-Solicitation Agreement dated December 18, 2022 between Lehman E. Newton, III and SM Energy Company \(filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 21, 2022, and incorporated herein by reference\)](#)
- [10.20†](#) [Non-Competition and Non-Solicitation Agreement dated December 29, 2022 between David Copeland and SM Energy Company \(filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 30, 2022, and incorporated herein by reference\)](#)
- [10.21†](#) [SM Energy Company Equity Incentive Compensation Plan, amended and restated effective as of May 22, 2018 \(filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 12, 2018, and incorporated herein by reference\)](#)
- [10.22*†](#) [Form of Performance Share Unit Award Agreement as of July 1, 2023](#)
- [10.23*†](#) [Form of Restricted Stock Unit Award Agreement as of July 1, 2023](#)
- [21.1*](#) [Subsidiaries of Registrant](#)
- [23.1*](#) [Consent of Ernst & Young LLP](#)
- [23.2*](#) [Consent of Ryder Scott Company L.P.](#)
- [24.1*](#) [Power of Attorney](#)
- [31.1*](#) [Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002](#)
- [31.2*](#) [Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002](#)
- [32.1**](#) [Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002](#)
- [97.1*†](#) [Policy Relating to Recovery of Erroneously Awarded Compensation](#)

[99.1*](#) [Ryder Scott Audit Letter](#)

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.LAB*	Inline XBRL Label Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101.INS)

* Filed with this report.

** Furnished with this report.

*** Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Exchange Act.

† Exhibit constitutes a management contract or compensatory plan or agreement.

†† Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.

+ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) *Financial Statement Schedules*. Please refer to Item 15(a) above.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

SM ENERGY COMPANY

(Registrant)

Date: February 22, 2024

By: /s/ HERBERT S. VOGEL
Herbert S. Vogel
President and Chief Executive Officer
(Principal Executive Officer)

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Herbert S. Vogel and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2023, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ HERBERT S. VOGEL</u> Herbert S. Vogel	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 22, 2024
<u>/s/ A. WADE PURSELL</u> A. Wade Pursell	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2024
<u>/s/ PATRICK A. LYTLE</u> Patrick A. Lytle	Vice President - Chief Accounting Officer and Controller (Principal Accounting Officer)	February 22, 2024

Signature	Title	Date
<u>/s/ JULIO M. QUINTANA</u> Julio M. Quintana	Chairman of the Board of Directors	February 22, 2024
<u>/s/ CARLA J. BAILO</u> Carla J. Bailo	Director	February 22, 2024
<u>/s/ STEPHEN R. BRAND</u> Stephen R. Brand	Director	February 22, 2024
<u>/s/ RAMIRO G. PERU</u> Ramiro G. Peru	Director	February 22, 2024
<u>/s/ ANITA M. POWERS</u> Anita M. Powers	Director	February 22, 2024
<u>/s/ ROSE M. ROBESON</u> Rose M. Robeson	Director	February 22, 2024
<u>/s/ WILLIAM D. SULLIVAN</u> William D. Sullivan	Director	February 22, 2024