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

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2023

OR

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

For the transition period from _____ to_____

Commission File Number: 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**34-1312571**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code **(817) 870-2601**

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

Title of Each Class	Trading Symbol	Name of each exchange on which registered
Common Stock, $.01 par value	RRC	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 during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

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 voting and non-voting common equity held by non-affiliates as of June 30, 2023 was $7,720,683,000. This amount is based on the closing price of registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

As of February 19, 2024, there were 242,119,571 shares of Range Resources Corporation common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be furnished to stockholders in connection with its 2024 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates, are incorporated by reference in Part II, Item 5 and Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to "Range," "we," "us" or "our" are to Range Resources Corporation and its directly and indirectly owned subsidiaries. Unless otherwise noted, all information in the report relating to natural gas, natural gas liquids and crude oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption "Glossary of Certain Defined Terms" at the end of Items 1 & 2. Business and Properties of this report.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K 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"). These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation, operational and financial strategies: drilling plans; planned wells; rig count; our 2024 capital budget; reserve estimates; financial flexibility; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources and the benefits thereof. These statements typically contain words such as "anticipates," "believes," "estimates," "expects," "intend," "may," "outlook," "plans," "projects," "targets," "should," "would" or similar words, indicating that future outcomes are uncertain. Such forward-looking statements are intended to be subject to the safe harbor protections provided by the federal securities law.

While we believe our assumptions concerning future events are reasonable, these expectations may not prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward looking statements including, but not limited to:

- conditions in the oil and gas industry, including supply and demand levels for natural gas, crude oil and natural gas liquids ("NGLs") and the resulting impact on price;
- the availability and volatility of securities, capital or credit markets and the cost of capital to fund our operation and business strategy;
- accuracy and fluctuations in our reserves estimates due to regulations, reservoir performance or sustained low commodity prices;
- lack of, or disruption in, access to pipelines or other transportation methods;
- ability to develop existing reserves or acquire new reserves;
- drilling and operating risks;
- well production timing;
- changes in the regulatory climate, either nationally or in our key operating market, that result in difficulty obtaining necessary approvals and permits;
- changes in geopolitical or economic conditions, including changes in interest rates and inflation rates, both domestically and internationally and more specifically in our key operating market;
- prices and availability of goods and services, including drilling rigs, material, labor and third-party infrastructure;
- unforeseen hazards such as weather conditions, health pandemics, acts of war or terrorist acts;
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems or breaches of the information technology systems, facilities and infrastructure of third parties with which we transact business;
- changes in safety, health, environmental, tax and other regulations or requirements or initiatives including those addressing the impact of global climate change, air emissions, waste or water management;
- the availability, cost, terms and timing of issuance or execution of competition for and challenges to mineral licenses and leases and governmental and other permits and right-of-way and our ability to retain mineral leases;
- other geological, operating and economic considerations;
- risks related to our derivative activities;
- non-performance by third parties of their contractual obligations; or
- other factors discussed in Items 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures about Market Risk and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Range Resources Corporation, a Delaware corporation, is a Fort Worth, Texas-based independent natural gas, NGLs and crude oil and condensate company, engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian region of the United States. Our principal area of operations is the Marcellus Shale in Pennsylvania. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). We also maintain field offices in our area of operations. Our common stock is listed and traded on the New York Stock Exchange (the "NYSE") under the ticker symbol "RRC." Range Resources Corporation was incorporated in 1980. At December 31, 2023, we had 241.0 million shares outstanding. At year-end 2023, our proved reserves had the following characteristics:

- 18.1 Tcfe of proved reserves;
- 64% natural gas, 34% NGLs and 2% crude oil and condensate;
- 64% proved developed;
- nearly 100% operated;
- a reserve life index of approximately 22 years (based on fourth quarter 2023 production);
- a pretax present value of $7.9 billion of future net cash flows, discounted at 10% per annum ("PV-10"[(a)]); and
- a standardized after-tax measure of discounted future net cash flows of $6.8 billion.

(a) PV-10 is considered a non-GAAP financial measure as defined by the U.S. Securities and Exchange Commission (the "SEC"). We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $1.1 billion at December 31, 2023. PV-10 for December 31, 2023 was determined using NYMEX benchmark prices of $2.62 per mcf for natural gas and $78.10 per bbl for oil.

Our estimated proved reserves increased slightly when compared to the prior year. Reserve additions were the result of a successful development program and completion optimizations that resulted in improved well performance. The 2023 reserve additions from drilling, a positive revision of 280.2 Bcfe for previously proved undeveloped properties added back to our five-year development plan and a positive performance revision of 701.4 Bcfe due to improved well performance and longer laterals were partially offset by lower prices, 2023 production volumes of 780.6 Bcfe and 370.6 Bcfe of reserves reclassified to unproved because these wells are no longer expected to be drilled within the original five-year development horizon. We believe these unproved reserves are likely to be included in our future proved reserves when these locations are added back into our five-year development plan.

Highlights of our 2023 production were:

- total production of 538.1 Bcf of natural gas, 37.9 Mmbbls of NGLs and 2.5 Mmbbls of crude oil and condensate; and
- average daily production of 2.14 Bcfe per day compared to 2.12 Bcfe per day in 2022.

Executive Summary for 2023

Because our production is approximately 69% natural gas, natural gas prices are generally the primary variable in our financial results. Over the last few years, New York Mercantile Exchange ("NYMEX") natural gas prices have been volatile. Since the beginning of 2021, the monthly close for natural gas prices has been as low as $1.99 per Mmbtu and as high as $9.35 per Mmbtu. The prices we receive for all our products are largely based on current market prices which are beyond our control but are managed through diversity in our sales agreements combined with an active commodity price hedging program. Currently, our focus is on generating free cash flow through controlling costs and operational efficiencies, while strengthening our balance sheet and returning free cash flow to stockholders. During 2023, we:

- realized cash flow from operating activities of $977.9 million;
- realized an improvement in our debt metrics from year-end 2022;
- made quarterly dividend payments in each quarter for a total distribution of $77.2 million;
- repurchased approximately $19.0 million of our common stock;
- executed opportunistic debt reductions of $61.6 million while accumulating $212.0 million of cash on hand;
- reduced transportation, gathering, processing and compression per mcfe 11% from 2022;

- reduced our general and administrative expense per mcfe 5% from 2022;
- reduced our interest expense per mcfe 24% from 2022;
- reduced our depletion, depreciation and amortization rate per mcfe 2% from 2022;
- our estimates of proved reserves at December 31, 2023 totaled 18.1 Tcfe which includes 207.3 Bcfe of drilling additions;
- completed the MiQ certification process (an independent framework for assessing methane emissions) for our southwest Pennsylvania operations and earned an "A" grade;
- continued with our implementation of the use of compressed air pneumatic controllers to meaningfully reduce our methane and carbon emissions;
- continued utilizing an electric hydraulic fracturing fleet along with dual fuel drilling rigs;
- achieved a 28% reduction in number of workforce recordable injuries compared to 2022 with no employee recordable injuries in 2023; and
- achieved a 70% reduction in preventable vehicle incidents compared to 2022.

Available Information

Our corporate website is available at http://www.rangeresources.com. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing we make with the SEC. We make available, free of charge on our website, the annual report on Form 10-K, our proxy statement, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our corporate sustainability report, our Corporate Governance Guidelines, the charters of each board committee and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including our President and Chief Executive Officer and Chief Financial Officer.

The SEC maintains an internet website that contains reports, proxy and information statements and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Our Business Strategy

Our overarching business objective is to build stockholder value through returns-focused development of our natural gas properties. Our strategy to achieve our business objective is to generate consistent cash flows from reserves and production through internally generated drilling projects. We routinely evaluate complementary, value-based acquisitions and dispositions. Our strategy requires us to make significant investments and financial commitments in technical staff, acreage, seismic data, drilling and completion technology and gathering and transportation arrangements to build drilling inventory and market our products. Our strategy has the following key elements:

- commit to environmental protection and worker and community safety;
- concentrate in our core operating area;
- focus on cost efficiency;
- maintain a high-quality, multi-year drilling inventory;
- maintain a long-life reserve base with a low base decline rate;
- market our products to a large number of customers in diverse markets under a variety of commercial terms;
- maintain operational and financial flexibility; and
- provide employee equity ownership and incentive compensation aligned with our stakeholders' interests.

These elements are anchored by our interests in the Marcellus Shale located in Pennsylvania which is anticipated to have remaining productive life in excess of 50 years.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement technologies and commercial practices to minimize potential adverse impacts from the development of our properties on the environment, worker health and safety and the safety of the communities where we operate. We analyze and review performance while striving for continual improvement by working with peer companies, regulators, non-governmental organizations, industries not related to the oil and natural gas industry and other engaged stakeholders. We expect every employee to maintain safe operations, minimize environmental impact and conduct their daily business with the highest ethical standards. We have published on our website our 2023 Corporate Sustainability Report which includes more information related to our sustainability practices.

Concentrate in Our Core Operating Area. We currently operate in Pennsylvania. Concentrating our drilling and producing activities allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in our core area also allows us to pursue our goal of consistent production at attractive returns. We intend to further develop our acreage and improve our operating and financial results through the use of technology and detailed analysis of our properties. We periodically evaluate and pursue acquisition opportunities (including opportunities to acquire particular natural gas and oil properties or entities owning natural gas and oil assets) and at any given time we may be in various stages of evaluating such opportunities.

Focus on Cost Efficiency. We concentrate in areas which we believe to have sizable hydrocarbon deposits in place that will allow economic production while controlling costs. Because there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term stockholder value creation. We endeavor to control costs such that our cost to find, develop and produce natural gas, NGLs and oil is one of the lowest in the industry. We operate almost all of our total net production and believe that our extensive knowledge of the geologic and operating conditions in the areas where we operate provides us with the ability to achieve operational efficiencies.

Maintain a High-Quality Multi-Year Drilling Inventory. We focus on areas with multiple prospective and productive horizons and development opportunities. We use our technical expertise to build and maintain a multi-year drilling inventory. We believe that a large, high-quality multi-year inventory of drilling projects increases our ability to efficiently plan for economic production. Currently, we have an estimated 30 million lateral feet of drilling inventory in the Marcellus Shale, both proved and unproved.

Maintain a Long-Life Reserve Base with a Low Base Decline Rate. Long-life natural gas and oil reserves provide a more stable platform than short-life reserves. Long-life reserves with relatively low decline rates reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life natural gas and oil reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Long-life reserves also offer upside from technology enhancements.

Market Our Products to a Large Number of Customers in Diverse Markets Under a Variety of Commercial Terms. We market our natural gas, NGLs, crude oil and condensate to a large number of customers in both domestic and international markets to maximize cash flow and diversify risk. We hold numerous firm transportation contracts on multiple pipelines to enable us to transport and sell natural gas and NGLs in the Midwest, Gulf Coast, Southeast, Northeast and international markets. We sell our products under a variety of price indexes and price formulas that assist us in optimizing regional price differentials and commodity price volatility.

Maintain Operational and Financial Flexibility. Because of the risks involved in drilling, coupled with changing commodity prices, we are flexible and may adjust our capital budget throughout the year. We believe our asset base, revenue diversity, low cost structure and stronger balance sheet provides us the flexibility we need to thrive across various commodity price environments. We also believe in maintaining ample liquidity, using commodity derivatives to help stabilize our realized prices and focusing on financial discipline. We believe this provides more predictable cash flows and financial results. With no debt maturities until 2025, a year-end 2023 cash balance of $212.0 million and $1.5 billion in committed borrowing capacity under our bank credit facility, we are well-positioned to continue to improve our balance sheet strength.

Provide Employee Equity Ownership and Incentive Compensation Aligned with Our Stakeholders' Interests. We want our employees to think and act like business owners. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees are eligible to receive equity grants. As of December 31, 2023, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $190.1 million. We seek to align our incentive compensation with stakeholders' interests and key business objectives and members of our board of directors annually engage with stockholders to discuss our incentive compensation framework.

Our Strengths

We believe the following strengths will help us achieve our business goals:

- ***Natural gas and NGLs resource base in the Marcellus Shale.*** Substantially all of our leasehold acreage is located in one of the largest natural gas plays in the world. We believe the majority of our properties are well positioned in the core of the Marcellus Shale. Our production for the year ended December 31, 2023 was approximately 69% natural gas, 29% NGLs and 2% crude oil and condensate.
- ***Multi-decade drilling inventory in the core of the Marcellus Shale.*** We have identified a multi-year inventory of drilling locations that we believe provides attractive growth and return opportunities.
- ***High degree of operational control.*** We are the operator of almost all of our total net production. This operating control allows us to better execute our strategies of enhancing returns through operational and cost efficiencies and increasing

recovery of hydrocarbons by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation process. We retain the ability to increase or decrease our capital expenditure program in response to commodity price outlooks.

- ***Experienced management team.*** Our management team has extensive experience in executing a multi-rig development drilling program, planning long-term logistics, marketing production and prudent capital allocation.

Significant Accomplishments in 2023

- ***Proved reserves*** – Total proved reserves were 18.1 Tcfe, a slight increase from the prior year. This achievement is the result of existing quality production and efficient development. We believe our high quality, substantial inventory of Marcellus Shale drilling locations provides the basis for future proved reserves to be efficiently developed by our skilled technical teams.
- ***Production*** – In 2023, our production averaged 2.14 Bcfe per day compared to 2.12 Bcfe per day in 2022. Our capital program is designed to allocate investments based on projects that maximize returns while minimizing controllable costs associated with production activities. We intend to continue a disciplined investment strategy in the Marcellus Shale.
- ***Focus on financial flexibility*** – As of December 31, 2023, we maintained a $4.0 billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity of $1.5 billion. We endeavor to maintain a strong liquidity position. In 2023, we reduced our aggregate principal amount of debt by $80.6 million. We ended 2023 with strong liquidity with $1.3 billion available under the credit facility and cash on hand of $212.0 million. Actual capital budget spending was within our announced spending range. As we have done historically, we may adjust our capital program or use derivatives to protect a portion of our future cash flow from commodity price volatility to reduce the risk of returns on investment and maintain ample liquidity.
- ***Successful drilling program*** – In 2023, we drilled 50 gross natural gas wells and our overall drilling success rate was 100%. We continue to maintain and optimize a sufficient inventory of drilled lateral footage which is critical to our ability to consistently sustain production each year on a cost effective and efficient basis. Controlling the costs to find, develop and produce natural gas, NGLs and oil is critical in creating long-term stockholder value. Our focus areas are characterized by a large, contiguous acreage position and multiple stacked geologic horizons.
- ***Focus on safe, responsible and sustainable operations*** – We believe we are on track to achieve our goal of net zero GHG emissions by year-end 2025, which includes Scope 1 and Scope 2 emissions. We continued to recycle approximately 100% of our produced water. Electric and dual fuel drilling and completion equipment is used to reduce emissions. We had no serious injuries for employees or contractors during the year.

Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our exploration and production operations are limited to onshore United States.

Outlook for 2024

For 2024, we expect our capital budget to be in the range of $620 million to $670 million for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. This budget includes $575 million to $590 million for drilling costs and $45 million to $80 million for acreage and other expenditures and is expected to achieve 2024 production similar to 2023 production volumes. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. Throughout the year, we allocate capital on a project-by-project basis. Our expectation for 2024 is for our capital expenditure program to be funded with operating cash flows. However, in the event our 2024 capital requirements exceed our internally generated cash flow, we may reduce the capital budget, draw on our bank credit facility and/or debt or equity financing may be used to fund these requirements. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2024 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions.

Our primary near-term focus includes the following:

- operate safely while being good stewards of the environment;
- achieve competitive returns on investments;
- manage liquidity and further improve financial strength;

- focus on organic opportunities through disciplined capital investments;
- improve operational efficiencies and economic returns;
- continue to reduce emissions and to achieve our announced target of net-zero Scope 1 and Scope 2 GHG emissions by year-end 2025;
- attract and retain quality employees; and
- align employee incentives with our stockholders' interests and key business objectives.

Proved Reserves

The following table sets forth our estimated proved reserves for years ended 2023, 2022 and 2021 based on the average of prices on the first day of each month of the given calendar year, in accordance with SEC rules. Oil includes both crude oil and condensate. We have no natural gas, NGLs or oil reserves from non-traditional sources. Additionally, we do not provide optional disclosures of probable or possible reserves.

	Summary of Oil and Gas Reserves as of Year-End Based on Average Prices				
Reserve Category	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [a]	%
As of December 31, 2023:					
Proved					
Developed	7,631,202	629,379	21,396	11,535,852	64%
Undeveloped	3,979,546	411,388	21,566	6,577,273	36%
Total Proved	11,610,748	1,040,767	42,962	18,113,125	100%
As of December 31, 2022:					
Proved					
Developed	7,230,313	594,931	22,213	10,933,180	60%
Undeveloped	4,567,659	409,027	20,443	7,144,476	40%
Total Proved	11,797,972	1,003,958	42,656	18,077,656	100%
As of December 31, 2021:					
Proved					
Developed	6,809,849	577,507	23,834	10,417,887	59%
Undeveloped	4,642,232	423,798	28,762	7,357,597	41%
Total Proved	11,452,081	1,001,305	52,596	17,775,484	100%

[a] Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Reserve Estimation Procedures and Audits

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We have established internal controls over our reserves estimation process and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC requirements. We also had Netherland, Sewell & Associates, Inc., an independent petroleum consultant, conduct an audit of our year-end 2023 reserves. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates. This engineering firm was selected for its geographic expertise and its historical experience in engineering certain properties. The proved reserve audits performed for 2023, 2022 and 2021, in the aggregate, represented 96%, 96% and 97% of our proved reserves. The reserve audits performed for 2023, 2022 and 2021, in the aggregate, represented 99%, 96% and 97% of our 2023, 2022 and 2021 associated pretax present value of proved reserves discounted at ten percent. A copy of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical person at our independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultant to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserve estimation process, our senior management reviews and approves significant changes to our proved reserves. We provide historical information to our consultant for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. Our consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. Our reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area, some of our estimates may be greater and some may be less than the estimates of the reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences, if any, are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been approximately 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, Mr. Alan Farquharson, who reports directly to our President and Chief Executive Officer. Our Senior Vice President of Reservoir Engineering and Economics holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than forty years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions. During the year ended December 31, 2023, we did not file any reports with any federal authority or agency with respect to our estimate of natural gas and oil reserves.

Reserve Technologies

Proved reserves are those quantities of natural gas, NGLs and oil that 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal technical staff employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, decline curve analysis, well logs, geologic maps and available downhole and production data, seismic data, well test data, reservoir simulation modeling and implementation and application of enhanced data analytics.

Proved undeveloped reserves (or "PUDs") include reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a major expenditure is required for completion. PUD reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic production. Undrilled locations may be classified as having PUD reserves only if an ability and intent has been established to drill the reserves within five years, unless specific circumstances justify a longer time period.

Reporting of Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2023, NGLs represented approximately 34% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to our customers. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2023 averaged approximately 32% of the average price for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. We currently include ethane in our proved reserves which match volumes to be delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves

As of December 31, 2023, our PUDs totaled 21.6 Mmbbls of crude oil, 411.4 Mmbbls of NGLs and 4.0 Tcf of natural gas, for a total of 6.6 Tcfe. Costs incurred in 2023 relating to the development of PUDs were approximately $495.1 million. All PUD drilling locations are scheduled to be drilled prior to the end of 2028. As of December 31, 2023, we have 90.2 Bcfe of reserves that have been reported for more than five years from their original booking date, which are in the process of being drilled and completed and expected to turn to sales in 2024. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 937.9 Bcfe of PUDs into proved developed reserves;
- addition of 178.8 Bcfe new PUDs from drilling; and
- 191.9 Bcfe net positive revision which includes an addition of 280.2 Bcfe for previously proved undeveloped properties added back to our five year development plan and positive revisions for the impact of improved well performance and longer laterals offset by 370.6 Bcfe of reserves reclassified to unproved because of previously planned wells not expected to be drilled within their original five-year development horizon.

For an additional description of changes in PUDs for 2023, see Note 15 to our consolidated financial statements. We believe our PUDs reclassified to unproved can be included in our future proved reserves as these locations are added back into our five-year development plan.

Proved Reserves (PV-10)

The following table sets forth the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years. Our reserve estimates do not include any probable or possible reserves (in millions, except prices):

	2023	2022	2021	2020	2019
Future net cash flows	$ 54,390	$ 78,650	$ 39,919	$ 9,795	$ 22,179
Present value:					
Before income tax	7,926	29,554	14,868	2,981	7,561
After income tax (Standardized Measure)	6,838	24,545	12,485	2,846	6,629
Benchmark prices (NYMEX):					
Gas price (per mcf)	2.62	6.36	3.60	1.98	2.58
Oil price (per bbl)	78.10	94.13	66.34	39.77	55.73
Wellhead prices:					
Gas price (per mcf)	2.20	6.08	3.30	1.68	2.38
Oil price (per bbl)	68.32	87.14	59.35	30.13	49.24
NGLs price (per bbl)	24.91	38.35	28.41	16.14	17.32

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, operating expenses and production taxes). Revenues are based on a twelve-month unweighted average of the first day of the month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Production, Sales Price and Production Costs

The following presents historical information about our total and average daily production volumes for natural gas, NGLs and oil; average sales prices and average production costs:

	Year Ended December 31,		
	2023	2022	2021
Production Volumes:			
Natural gas (Mmcf)	538,085	539,443	541,021
NGLs (Mbbls)	37,940	36,392	36,373
Crude oil and condensate (Mbbls)	2,475	2,716	3,044
Total Mmcfe [(a)]	780,575	774,089	777,523
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 2.29	$ 6.24	$ 3.50
NGLs (per bbl)	24.61	35.96	31.23
Crude oil and condensate (per bbl)	67.29	87.79	60.11
Total (per mcfe) [(a)]	2.99	6.34	4.13
Production Costs:			
Lease operating (per mcfe)	$ 0.12	$ 0.11	$ 0.10
Taxes other than income (per mcfe) [(c)]	0.03	0.05	0.04

(a) Oil and NGLs volumes are converted at the rate of one barrel equals six mcf based on approximate relative energy content.

(b) Does not include derivative settlements or deductions for third-party transportation, gathering or processing costs.

(c) Includes Pennsylvania impact fee.

Property Overview

Our natural gas and oil operations are concentrated in the Appalachian region of the United States, and more specifically, in the Marcellus Shale in Pennsylvania. Our properties consist of interests in developed and undeveloped natural gas and oil leases. These interests entitle us to drill for and produce natural gas, NGLs, crude oil and condensate from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests.

We hold a large portfolio of drilling opportunities beyond the five-year horizon of proved reserves and therefore a significant unbooked resource potential within the Marcellus, Utica/Point Pleasant and Upper Devonian formations. We own 1,466 net producing wells in Pennsylvania, almost all of which we operate. Our average working interest in this region is 95%. As of December 31, 2023 we have approximately 860,000 gross (753,000 net) acres under lease. During 2023, we averaged approximately two horizontal drilling rigs in the field and expect to run an average of two horizontal drilling rigs throughout 2024. Substantially all of our reserves and production are located in the Marcellus Shale.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2023. If we own both a royalty and a working interest in a well, such interest is included in the table below. Wells are classified as natural gas or crude oil according to their predominant production stream. We do not have any dual completions.

	Total Wells		Average Working Interest
	Gross	Net	
Natural gas	1,549	1,466	95%
Crude oil	1	—	3%
Total	1,550	1,466	95%

Productive wells are producing wells and wells mechanically capable of production. The day-to-day operations of natural gas and oil properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Drilling Activity

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. This information should not be indicative of future performance nor should it be assumed that there was any correlation between the number of productive wells and the natural gas and oil reserves generated thereby. As of December 31, 2023, we had 27 gross (26 net) wells in the process of drilling or active completions stage. In addition, there were 16 gross (16 net) wells waiting on completion or waiting on pipelines at year-end 2023.

	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	50.0	47.4	60.0	59.0	58.0	57.1
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	—	—	—	—	1.0	1.0
Dry	—	—	—	—	—	—
Total wells						
Productive	50.0	47.4	60.0	59.0	59.0	58.1
Dry	—	—	—	—	—	—
Total	50.0	47.4	60.0	59.0	59.0	58.1
Success ratio	100%	100%	100%	100%	100%	100%

Gross and Net Acreage

We own interests in developed and undeveloped natural gas and oil acreage. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves. The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2023. Acreage related to option acreage, royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Michigan	111	111	—	—	111	111
New York	—	—	2,265	567	2,265	567
Oklahoma	22,189	9,349	—	—	22,189	9,349
Pennsylvania	791,405	690,550	60,140	57,134	851,545	747,684
Texas	6,273	4,356	—	—	6,273	4,356
West Virginia	5,876	5,197	—	—	5,876	5,197
	825,854	709,563	62,405	57,701	888,259	767,264
Average working interest		86%		92%		86%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2024	11,496	10,711	19%
2025	9,393	8,749	15%
2026	17,594	17,086	30%
2027	10,601	10,494	18%
2028	9,733	8,786	15%

In all cases, the drilling of a commercial well will hold acreage beyond the lease expiration date. We have leased acreage that is subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. However, we have in the past been able, and expect in the future to be able to extend the lease terms of some of these leases and sell or exchange some of these leases with other companies. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and we expect to allow additional acreage to expire in the future. When we do not intend to drill on a property prior to expiration, we have allowed acreage to expire. We also believe acres needed in the future for our development plans can be leased again. We currently have no proved undeveloped reserve locations scheduled to be drilled after lease expiration.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty or overriding royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

Delivery Commitments

For a discussion of our delivery commitments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Delivery Commitments*.

Human Capital Management

We believe our employees provide the foundation of our success. Successful execution of our strategy is dependent on attracting, developing and retaining our skilled employees and members of our management team. The abilities, experience and industry knowledge of our employees significantly benefit our operations and performance. In order to maximize the contributions of our employees, we regularly evaluate, modify and enhance our policies and practices, including compensation to increase employee engagement, productivity and efficiency. As of January 1, 2024, we had 548 full time employees, none of whom are currently covered by a labor union or other collective bargaining arrangement.

Compensation and Benefits. We review compensation for all employees at least annually to adjust for market conditions and to attract and retain a highly skilled workforce. We encourage our employees to take full advantage of our benefits and programs we offer. In addition to competitive base wages, other benefits include an annual bonus plan, long-term incentive plan, company-match 401(k) plan, healthcare and insurance benefits, flexible spending accounts and employee assistance programs.

Our compensation program includes eligibility for all full-time employees to receive equity awards which we believe is uncommon among our peers and encourages every employee to think like an owner of the business and be vested in its success. We believe these practices, and those further described below, are the key drivers in our very low voluntary turnover rates, which averaged less than 3.5% over the five-year period ended December 31, 2023. We believe our low attrition rate is in part a result of our corporate culture focused on teamwork and a commitment to employee development and career advancement.

Health and Safety. We believe health and safety is a core value and ingrained in all aspects of our business. This value is reflected in our strong safety culture that emphasizes personal responsibility and safety leadership both for our employees and our contractors on our worksites. Our comprehensive environmental, health and safety (EHS) management system establishes a corporate governance framework for EHS compliance and performance and covers all elements of our operating lifecycle. These practices and the commitment of our management and our employees to our culture of safety have resulted in only two OSHA recordable incidents in 3.5 million work hours over the three-year period from 2021 through 2023, for an average employee Total Recordable Incident Rate of 0.11 over that three-year period.

Recruiting, Hiring and Advancement. Due to the cyclical nature of our business and the fluctuations in activity that can occur, we take a conservative approach to our headcount, carefully evaluating whether a new hire is necessary for an open position or whether we can fill the position by expanding the role of a current employee or several employees. In this way, we provide employees with opportunities to learn new roles and develop their skills horizontally and vertically and limit or minimize layoffs and fluctuations when downturns occur. We support employees in pursuing training opportunities to expand their professional skills. We have also implemented development programs that are designed to build leadership capabilities at all levels.

We identify qualified candidates by promoting positions internally, engaging in recruiting through our website platforms, campus outreach, internships and attending job fairs. In our recruiting and hiring efforts, we seek to foster a culture of mutual respect and strictly comply with all applicable federal, state and local laws governing non-discrimination in employment. We treat all applicants with the same high level of respect regardless of their gender, ethnicity, religion, national origin, age, marital status, political affiliation, sexual orientation, gender identity, disability or protected veteran status. This philosophy extends to all employees throughout the lifecycle of employment.

Additional information about our commitment to human capital management is available on our website. Note that the information on our website is not incorporated by reference into this filing.

Executive Officers of the Registrant

Our executive officers and their ages as of February 1, 2024, are as follows:

	Age	Position
Dennis L. Degner	51	Chief Executive Officer and President
Mark S. Scucchi	46	Executive Vice President – Chief Financial Officer
Erin W. McDowell	45	Senior Vice President – General Counsel and Corporate Secretary
Dori A. Ginn	66	Senior Vice President – Controller and Principal Accounting Officer

Dennis L. Degner, chief executive officer and president, joined Range in 2010. Mr. Degner was named chief executive officer effective May 21, 2023. Mr. Degner previously served as chief operating officer and has more than 25 years of oil and gas experience, having worked in a variety of technical and managerial positions across the United States including Texas, Louisiana, Wyoming, Colorado and Pennsylvania. Prior to joining Range, Mr. Degner held positions with EnCana, Sierra Engineering and Halliburton. Mr. Degner is a member of the Society of Petroleum Engineers and has been published for his work on active roles played in the deployment of new technologies. Mr. Degner holds a Bachelor of Science Degree in Agricultural Engineering from Texas A&M University.

Mark S. Scucchi, executive vice president – chief financial officer, joined Range in 2008. Mr. Scucchi was named senior vice president – chief financial officer in 2018 and executive vice president in 2023. Previously, Mr. Scucchi served as vice president – finance & treasurer. Prior to joining Range, Mr. Scucchi was with JPMorgan Securities providing commercial and investment banking services to small and mid-cap technology companies. Before joining JPMorgan Securities, Mr. Scucchi spent a number of years at Ernst & Young LLP in the audit practice. Mr. Scucchi earned a Bachelor of Science in Business Administration from Georgetown University and a Master of Science in Accountancy from the University of Notre Dame. Mr. Scucchi is a CFA Charterholder and a licensed certified public accountant in the state of Texas.

Erin W. McDowell, senior vice president – general counsel and corporate secretary, joined Range in January 2015 as division counsel for the Appalachia Division and was promoted to vice president, deputy general counsel & assistant corporate secretary before being appointed to general counsel and corporate secretary in March 2023. Ms. McDowell has nearly 20 years of legal experience. Prior to joining Range, Ms. McDowell spent over ten years with the law firm Eckert Seamans Cherin & Mellott in the areas of commercial litigation and environmental regulatory counseling. Ms. McDowell graduated from Bucknell University, magna cum laude, with a Bachelor of Arts in Economics and Environmental Studies and then earned a Juris Doctor from the University of Pittsburgh School of Law.

Dori A. Ginn**,** senior vice president – controller and principal accounting officer, joined Range in 2001. Ms. Ginn has held the positions of financial reporting manager, vice president and controller before being elected to principal accounting officer in September 2009. Prior to joining Range, she held various accounting positions with Doskocil Manufacturing Company and Texas Oil and Gas Corporation. Ms. Ginn earned a Bachelor of Business Administration in Accounting from the University of Texas at Arlington. She is a certified public accountant licensed in the state of Texas.

Competition

Competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. We face competition for pipeline and other services to transport our product to markets, particularly in the Northeastern portion of the United States. We also face competition from companies that supply alternative sources of energy, such as wind, solar power and other renewables. Competition will increase as alternative energy technology becomes more reliable and governments throughout the world support or mandate the use of such alternative energy.

Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation, focus on price and cost management and safely operate our producing properties. We have a team of dedicated employees who represent the professional disciplines and sciences that we believe are necessary to allow us to maximize the long-term profitability and net asset value inherent in our physical assets. For more information, see Item 1A. Risk Factors.

Marketing and Customers

We market the majority of our natural gas, NGLs, crude oil and condensate production from the properties we operate for our working interest, and that of the other working interest owners. We pay our royalty owners from the sales attributable to our working interest. Natural gas, NGLs and oil purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our natural gas, NGLs and oil production that accounted for 10% or more of consolidated revenue, see Note 2 to our consolidated financial statements. Because alternative purchasers of natural gas and oil are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations. Production from our properties is marketed using methods that are consistent with industry practice. Natural gas is a commodity, and therefore, we typically receive market-based pricing for our produced natural gas. Sales prices for natural gas, NGLs and oil production are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions.

We contract with a third-party to process our natural gas and extract from the produced natural gas heavier hydrocarbon streams (consisting predominately of ethane, propane, isobutane, normal butane and natural gasoline). Our natural gas production is sold to utilities, marketing and midstream companies and industrial users. Our NGLs production is typically sold to petrochemical end users, marketers/traders (both domestically and internationally) and natural gas processors. Our oil and condensate production is sold to crude oil processors, transporters and refining and marketing companies.

We enter into derivative transactions with unaffiliated third parties for a varying portion of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas, NGLs and oil prices. For a more detailed discussion, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We incur gathering and transportation expense to move our production from the wellhead, tanks and processing plants to purchaser-specified delivery points. These expenses vary and are primarily based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. We also have processing contracts based on percent of proceeds. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. Our Appalachian production is transported on third-party pipelines on which we hold a certain amount of long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to utilize contracted transportation capacity.

We have not experienced significant difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to transport and market all of our production or obtain favorable prices. We have entered into several ethane agreements to sell or transport ethane from our Marcellus Shale area. For more information, see Item 1A. Risk Factors – *Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties.*

Seasonal Nature of Business

Generally, but not always, the demand for natural gas and propane decreases during the spring and fall months and increases during the winter months and, in some areas, also increases during the summer months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand. Exports can also impact demand based on the seasonality of global markets.

Markets

Our ability to produce and market natural gas, NGLs and oil profitably depends on numerous factors beyond our control. The effect of these factors cannot be accurately predicted or anticipated. Although we cannot predict the occurrence of events that may affect commodity prices or the degree to which commodity prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC. The NYSE, a private stock exchange, also requires us to comply with listing requirements for our common stock. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the NYSE listing rules and regulations of the SEC could subject us to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could also result in the de-listing of our common stock, which could have an adverse effect on the market price of our common stock. Compliance with some of these rules and regulations is costly and regulations are subject to change or reinterpretation.

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state and local regulations, mandates and trade agreements. Governmental policies affecting the energy industry, such as taxes, tariffs, duties, price controls, subsidies, incentives, foreign exchange rates and import and export restrictions, can influence the viability and volume of production of certain commodities, the volume and types of imports and exports, whether unprocessed or processed commodity products are traded, and industry profitability. For example, in the past the United States government has imposed tariffs on certain foreign imports and the resulting retaliation by those foreign governments has disrupted aspects of the energy market. Disruption and uncertainty of this sort can affect the price of oil and natural gas and may cause us to change our plans for exploration and production levels. An overview of relevant federal, state and local regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations, and the continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur, or past non-compliance with environmental laws or regulations may be discovered. See Item 1A. Risk Factors – *The natural gas industry is subject to extensive regulation*. We do not believe we are affected differently by these regulations than others in the industry.

General Overview. Our oil and gas operations are subject to various federal, state and local laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- leases;
- acquisition of seismic data;
- location of wells, pads, roads, impoundments, facilities or rights of way;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and completion of wells;
- issuance of permits in connection with exploration, drilling, production, gathering, processing and transportation;
- well production, maintenance, operations and security;
- spill prevention and containment plans;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of hazardous waste, fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- hydraulic fracturing;
- water withdrawal and water transfer;
- operation of underground injection wells to dispose of produced water and other liquids;
- marketing of production;
- transportation of production; and
- health and safety of employees and contract service providers.

In August 2005, the United States Congress ("Congress") enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (the "FERC"), in contravention of rules prescribed by the FERC. In January 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA. On January 11, 2024, FERC issued a final rule increasing the maximum civil penalty for violations of the NGA from $1,496,035 per day per violation to $1,544,521 per day per violation to account for inflation pursuant to the Federal Civil Penalties Inflation Adjustment Improvement Act of 2015. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to the FERC's jurisdiction which includes the reporting requirements under Order 704 (as defined and described below). Therefore, EPAct 2005 was a significant expansion of the FERC's enforcement authority. Range has not been affected differently than any other producer of natural gas by this act. Failure to comply with applicable laws and regulations with respect to EPAct 2005 could result in substantial penalties and the regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations with respect to EPAct 2005, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the FERC, other federal regulatory entities and the courts. We cannot predict when or whether any such proposals may become effective.

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million Mmbtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are required to report to the FERC, on May 1st of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, varies from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their impact, if any, on our operations. We believe that the regulation of intrastate gas pipeline transportation rates will not affect our operations in any way that is materially different from its effects on similarly situated competitors.

Natural gas processing. We depend on gas processing operations owned and operated by third parties. There can be no assurance that these processing operations will continue to be unregulated in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact our processing.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. We believe that our gathering facilities meet the tests the FERC has traditionally used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Thus, we cannot guarantee that the jurisdictional status of our gas gathering facilities will remain unchanged.

We depend on gathering facilities owned and operated by third parties to gather production from our properties, and therefore we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulations affect the rates charged for gathering services at any of these third-party facilities, we may also be affected by these changes. We do not anticipate that we would be affected differently than similarly situated gas producers.

Regulation of transportation and sale of oil and natural gas liquids. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). We do not believe these regulations affect us differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be just and reasonable. Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

The FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. Under the FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. For example, on July 1, 2023, oil pipelines regulated by FERC and utilizing this index system were able to increase their rates by over 13%, which amounts to the largest index rate increase since FERC initiated this methodology. Increases in liquids transportation rates may result in lower revenue and cash flow. In January 2022, the FERC revised the adjustment for this index to be based on Producer Price Index for Finished Goods minus 0.21% for the five year period from July 1, 2021 to June 30, 2026. This adjustment is subject to review every five years.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may include, but are not limited to:

- the acquisition of a permit before construction commences;
- restriction of the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines;
- governing the sourcing and disposal of water used in the drilling and completion process;
- limiting or prohibiting drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- requiring some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments; and
- imposing substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings.

These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

Oil and gas activities have increasingly faced opposition from certain organizations and, in certain areas, have been restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the Superfund law and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release or threatened release of a hazardous substance into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these 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 certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a hazardous substance under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA. In addition, certain state laws also regulate the disposal of oil and natural gas wastes. New state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

Waste handling. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry. In December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. As a result, on April 23, 2019, the EPA decided to retain its current position on the regulation of oil and gas waste pursuant to RCRA. Nevertheless, any future changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for many years for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial activities to prevent future contamination.

Water discharges and use. The Federal Water Pollution Control Act, as amended (the "CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas and oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Oil Pollution Act of 1990, as amended ("OPA"), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Underground Injection Control Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. In connection with our operations, Range may dispose of produced water in underground wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. However, because some states have become concerned that the disposal of produced water could, under certain circumstances, contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. We currently do not utilize underground injection in our operations.

Hydraulic fracturing. Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state environmental agencies and oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final regulations under the Clean Air Act (as defined below) governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, while the Federal Bureau of Land Management released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands in March 2015, on December 29, 2017, the United States Department of the Interior rescinded the 2015 rule that would have set new environmental limitations on hydraulic fracturing, or fracking, on public lands because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. On January 20, 2021, President Biden's first day in office, he issued an executive order which, among other things, revoked a series of executive orders, presidential memoranda, and draft agency guidance concerning environmental policy issued during the Trump administration. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania, have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. For example, in November 2023, Pennsylvania Governor Josh Shapiro instructed the Pennsylvania Department of Environmental Protection ("DEP") to take immediate action to pursue formal rulemaking and policy changes, including new requirements for the disclosure of chemicals used in drilling, improved control of methane emissions aligned with federal policy, stronger drilling waste protections (including inspection of secondary containment) and corrosion protections for gathering lines that transport natural gas. Certain states have prohibited hydraulic fracturing or imposed setbacks that severely limit where drilling and hydraulic fracturing can take place. Range currently does not have operations in any of those states. Local governments or political subdivisions also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. For instance, on February 25, 2021, the Delaware River Basin Commission, which supplies drinking water for more than 13 million people in Pennsylvania, Delaware, New Jersey, and New York, approved a final rule prohibiting high volume hydraulic fracturing in the Delaware River Basin, which includes a portion of the Marcellus Shale that overlaps the Delaware watershed, specifically in northeastern Pennsylvania and southern New York State. More recently, in December 2022, the Delaware River Basin Commission voted to prohibit wastewater from hydraulic fracturing operations from being deposited into the Delaware River Basin's waters or land. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements. As a result, we could also become subject to additional permitting requirements, new setback distances or experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. In December 2016, the EPA issued its final report on the potential of hydraulic fracturing to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases and inadequate treatment and discharge of wastewater which did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. However, the EPA’s report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing to impact drinking water resources, including ground water and surface water monitoring in areas with hydraulically fractured oil and gas production wells. Based on the EPA’s study, existing regulations and our practices, we do not believe our hydraulic fracturing operations are likely to impact drinking water resources, but the EPA study could result in initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our hydraulic fracturing operations have not resulted in material environmental liabilities. We do not maintain insurance policies intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover any alleged third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Air emissions. The Clean Air Act of 1963, as amended (the "Clean Air Act") and comparable state laws restrict the emission of air pollutants from many sources. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, on December 2, 2023, the EPA released a final rule on the New Source Performance Standards ("NSPS") to sharply reduce emissions of methane and other air pollution from oil and natural gas operations. The final rule, as released will, among other things (i) require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time, (ii) phase out routine flaring from natural gas wells, (iii) require the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies, (iv) leverage data collected by certified third parties to identify and address "super emitting" sources and eliminate or minimize emissions from common pieces of equipment used in oil and gas operations such as process controllers, pumps and storage tanks and (v) require proper documentation that wells are properly closed and plugged before monitoring is allowed to end. In response to feedback received during the rule's comment period, the EPA adjusted several provisions of the proposed rule to allow extended time for compliance including a two-year phase-in period for eliminating routine flaring of natural gas that is emitted from new oil wells. Further, on August 1, 2023, the EPA released a proposed rule to update the Greenhouse Gas Reporting Program for the Petroleum and Natural Gas category (subpart W). Upon finalization, this rule could potentially impact Range's greenhouse gas emissions reported to the EPA in future years. Also, in June 2018, the DEP adopted heightened permitting conditions for all newly permitted or modified natural gas compressor stations, processing plants and transmission stations constructed, modified, or operated in Pennsylvania in an effort to regulate emissions of the greenhouse gas at such sites. In furtherance of the DEP’s mission to regulate methane emissions, in December 2019, the DEP proposed a rule to regulate emissions of volatile organic compounds (including methane) at existing well sites and compressor stations, which, among other obligations, would require natural gas operators to perform quarterly leak detection and remediation. The proposed rule was reviewed by the Pennsylvania Office of the Attorney General followed by a sixty day public comment period. Thereafter, the Pennsylvania Environmental Quality Board (the "PEQB") adopted the proposed rulemaking and an additional public comment period on July 27, 2020. On May 4, 2022, the PEQB withdrew the rule. On May 18, 2022, the rule was bifurcated into two separate rules – one for conventional oil and gas sources and one for unconventional oil and gas sources. On June 14, 2022, the PEQB adopted the rule for unconventional oil and gas sources. At its October 12, 2022 meeting, the PEQB adopted the rule for conventional oil and gas sources. However, on November 14, 2022, the Pennsylvania House Environmental Resources & Energy Committee disapproved such final-omitted regulation triggering a 14-calendar-day legislative review period. Since this legislative review period would have extended past the December 16, 2022 deadline for Pennsylvania to submit to the EPA a plan implementing the regulation of VOC emissions from oil and gas sources, the PEQB, on November 30, 2022, adopted the rule for conventional oil and gas sources as an emergency certified final-omitted rulemaking and former Governor Tom Wolf certified that promulgation of such is necessary to respond to an emergency circumstance. On December 10, 2022, both the conventional and unconventional rules were published as final. Since then, certain organizations have implemented legal action against the PEQB for failure to follow the requirements for rulemaking applicable to the conventional oil and natural gas industry. Compliance with these or any similar subsequently enacted regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in the need for additional permitting and introducing potential permitting delays and increasing our capital expenditures and operating costs, which could adversely impact our business.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install the best available control technology to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We believe that our monitoring activities and reporting are in substantial compliance with applicable obligations.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years, such as the establishing of Title V and PSD permitting reviews for GHG emissions, as described in more detail above. Further, on December 8, 2021, President Biden signed an executive order whereby the government was directed to cut its GHG emissions by 65% by the end of this decade, before reaching carbon neutrality by 2050. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. For example, in August 2022, Congress enacted the Inflation Reduction Act, which among other things, adopted a methane emissions fee to be assessed against oil and gas operators. Thereafter, the EPA issued proposed rules regarding the calculation of the so-called waste emissions fee and collection of those fees. While Range's methane emissions intensity remains low and below the stated threshold as currently proposed, changes to the calculation of that fee could result in fees in the future.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal or state laws and regulations, or international compacts could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. On an international level, the United States was one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France the ("Paris Agreement") that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, which agreement formally entered into force on November 4, 2016. While the United States formally accepted that agreement in September 2016, on June 1, 2017, then President Trump determined to withdraw the United States from the Paris Agreement. Under the terms of the Paris Agreement, the earliest possible effective date for withdrawal by the United States was November 4, 2020. However, on January 20, 2021, President Biden signed an executive order directing the United States to rejoin the Paris Agreement, which became official on February 19, 2021. It is not yet clear how rejoining the Paris Agreement or any separately negotiated agreement could impact us.

Upon taking office in January 2021, President Biden announced that he would demand that Congress enact legislation in the first year of his presidency that (i) establishes milestone environmental targets no later than the end of his first term in 2025, (ii) makes a significant investment in clean energy and climate research and innovation and (iii) incentivizes the rapid development of clean energy innovations across the economy, especially in communities most impacted by climate change. For example, on January 20, 2021, President Biden issued Executive Order No. 13990 requiring the heads of all federal agencies to review any agency activity under the Trump administration that would be considered to be inconsistent with the Biden administration's environmental policies and consider suspending, revising, or rescinding those actions. As a result, in April 2021, the Secretary of the Interior issued two Secretarial Orders intended to prioritize action on climate change and revoking at least 12 orders issued under the Trump administration that are no longer consistent with the United States Department of the Interior's policy priorities under President Biden. Furthermore, on January 27, 2021, President Biden issued executive orders for the purpose of combating climate change including pausing new oil and gas leases on federal land and cutting fossil fuel subsidies. Finally, it should be noted that some scientists have concluded 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, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

We believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2023, nor do we anticipate that such expenditures will be material in 2024. However, we regularly incur expenditures and undertake projects to comply with environmental laws and to optimize our emissions performance. We anticipate those costs will continue to be incurred in the future.

Occupational health and safety. We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

btu. One British thermal unit, an energy equivalence measure. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

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

Dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

Exploratory well. A well drilled to find oil or natural gas in an unproved area or to find a new reservoir in an existing field previously found to be productive in another reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

mmbtu. One million British thermal units.

mmcf. One million cubic feet of gas.

mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated into these substances and sold.

Net acres or Net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Present Value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after-tax present value is the Standardized Measure.

Productive well. A well that is producing oil or gas or that is capable of production.

Proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed reserves. Proved 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 extracting equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved reserves. The quantities of crude oil, natural gas and NGLs that geological and engineering data can estimate with reasonable certainty to be economically producible within a reasonable time from known reservoirs under existing economic, operating and regulatory conditions prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved undeveloped reserves. Proved 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.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reserve life index. Proved reserves at a point in time divided by the then production rate (annually or quarterly).

Royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

Royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

tcfe. One trillion cubic feet of natural gas equivalents, with one barrel of NGLs or crude oil being equivalent to 6,000 cubic feet of natural gas.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

Unconventional play. A term used in the oil and gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation or other special recovery processes in order to achieve economic flow rates.

ITEM 1A. RISK FACTORS

While we utilize robust processes and resources to identify and manage risks, we are subject to various risks and uncertainties in the course of our business, some of which are comparable to the risks any business is exposed to and some that are unique to our operations. The following summarizes the known material risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering making or maintaining an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the section entitled Disclosures Regarding Forward-Looking Statements and other information included and incorporated by reference into this Annual Report on Form 10-K. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we believe not to be material based on the information we have at this time. If any of the events described below as risks actually occur, it could materially harm our business, financial condition or results of operations or impair our ability to implement our business plans or complete development activities as expected. In that case, the market price of our common stock could decline or, if severe enough, the entire value of an investment in our securities could become worthless.

Economic risks related to our business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to operate economically. Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. As a commodity business, the oil and gas industry is typically cyclical and we expect the volatility to continue. Natural gas prices are likely to affect us more than oil prices because approximately 64% of our proved reserves were natural gas as of December 31, 2023 and, at times in the past, natural gas prices have been low compared to our costs to produce. Natural gas, NGLs and oil prices fluctuate in response to changes in supply and demand, market uncertainty and other factors that are beyond our control. These factors include:

- events that impact domestic and foreign supply of, and demand for, natural gas, NGLs and oil, including impacts from global health pandemics and related concerns;
- the continued operation of liquefied natural gas (LNG) facilities to supply foreign markets with natural gas and the ability to transport the product to markets due to shipping restrictions or terrorist threats and attacks;
- changes in weather patterns and climate, including natural disasters such as hurricanes and tornadoes;
- technological advances affecting energy consumption, storage and energy supply;
- the production levels of non-OPEC countries, including production levels in the United States' shale plays;
- general economic conditions worldwide;
- the price and availability of, and demand for, alternative and competing forms of energy, such as nuclear, hydroelectric, wind and solar;
- the level of drilling, completion and production activities by other companies, and variability therein, in response to market conditions;
- the effect of worldwide energy conservation efforts;
- the ability of the members of OPEC and other exporting nations to agree to production controls;
- military, economic and political conditions in natural gas and oil producing regions;
- the cost of exploring for, developing, producing, transporting and marketing natural gas, NGLs and oil; and
- domestic (federal, state and local) and foreign governmental regulations and taxation, including further legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels.

The long-term effects of these and other factors on the prices of natural gas, NGLs and oil prices are uncertain. Historical declines in natural gas and NGLs commodity prices have adversely affected our business by:

- reducing the amount of natural gas, NGLs and oil that we can economically produce;
- reducing our revenues, operating income and cash flows;
- reducing the amount of cash flows available for capital expenditures;
- increasing the cost of obtaining capital, such as equity and debt financings; and
- reducing the standardized measure of discounted future net cash flows relating to natural gas, NGLs and oil.

If demand for natural gas, NGLs and oil is reduced, the prices we receive for and our ability to market and produce our natural gas, NGLs and oil may be negatively affected. Volatility in natural gas, NGLs and oil markets and the price we receive for our production is largely determined by various factors beyond our control. Production from natural gas and oil wells in some geographic areas of the United States has been or could be curtailed for considerable periods of time due to lack of local market demand and transportation and storage capacity. In the recent past, we have temporarily shut-in wells due to low commodity prices and it is possible that some of our wells may be shut-in in the future or sales terms may be less favorable than might otherwise be obtained should demand for our products decrease and/or prices decrease. Competition for markets has been vigorous and there remains uncertainty about prices purchasers will pay or the availability of sufficient storage, all of which could have a material adverse effect on our cash flows, results of operations and financial position.

We could experience periods of higher costs. These cost increases could reduce our profitability, cash flow and ability to conduct development activities as planned. We rely on third-party contractors to provide key services and equipment for our operations. Historically, our capital and operating costs have risen during periods of increasing oil, NGLs and gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling and completions activity increases; and increased taxes. Increased levels of drilling activity in the natural gas and oil industry could lead to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in our revenue, thereby negatively impacting our profitability, cash flow and ability to conduct development activities as planned and on budget.

Based on the cost inflation pressure experienced over the last few years, we continue to undertake actions and implement plans to strengthen our supply chain. Nevertheless, we expect to experience some supply chain constraints and inflationary pressure on our cost structure including steel, fuel and labor, among other items, for the foreseeable future. By continuing to focus on cost control initiatives and actions, which increase our drilling, completion and operating efficiencies, we are able to mitigate some inflationary pressures.

Our debt obligations may limit our liquidity and financial flexibility. We are a borrower under fixed rate senior notes and maintain a bank credit facility which had no debt outstanding as of December 31, 2023. Our exploration and development program requires substantial capital resources depending on the level of drilling and the expected cost of services. Existing operations also require ongoing capital expenditures. Increases in our level of debt may:

- require us to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations or return of capital to stockholders;
- may make us vulnerable to increases in interest rates;
- increase our vulnerability to a downturn in commodity prices or the general economy;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- limit our operating flexibility due to financial and other restrictive covenants; and
- limit our flexibility to maintain or grow our business and plan for, or react to, changes in our business and the industry in which we operate.

Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing our reserves. If our access to capital were limited as a result of various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to fund our operations and replace our reserves resulting in stress on our financial flexibility.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in natural gas, NGLs and oil prices adversely impact the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base and could result in a determination to lower our borrowing base, reducing our financial flexibility.

Disruptions or volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We benefit from continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to conduct our planned operations, our ability to manage our debt maturities and our flexibility to react to changing economic and business conditions. We are also exposed to some credit risk related to our bank credit facility to the extent that one or more of our lenders experiences liquidity problems and is unable to provide necessary funding to us under our existing revolving line of credit.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations. Our earnings and cash flow will fluctuate from year to year due to the variable nature of commodity prices. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek equity sales or restructure our debt. Our ability to restructure our debt will depend on the condition of the capital markets and our financial condition at such time. Any restructuring of debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our operations and our financial flexibility. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term cash flow relative to debt balances. Liquidity, asset quality, cost structure, product mix (natural gas, NGLs and crude oil) and projected commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt and could require us to post letters of credit or other forms of collateral for certain obligations. We cannot provide assurance that our current ratings will remain in effect for any given period of time or that a rating will not be downgraded in the future.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part. The terms of our senior indebtedness, including our revolving credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under our indentures or other loan agreements. Accordingly, should an event of default above certain thresholds occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obligated in such instance to satisfy all of our outstanding indebtedness but in all probability unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to continue our business plan, make capital expenditures and finance our operations.

Derivative transactions may limit our potential gains and involve other risks. To manage our exposure to commodity price volatility, we currently, and likely will in the future, enter into derivative arrangements, utilizing commodity derivatives ("hedges") with respect to a portion of our future production. Hedges are generally designed to lock in prices for commodities to limit volatility and increase the predictability of cash flow. These hedging transactions can limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas or oil sales prices we receive.

We cannot be certain that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. Furthermore, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by decreases in natural gas, NGLs or oil prices than our competitors who utilize derivative transactions. Lower natural gas, NGLs and oil prices over a longer term will also negatively impact our ability to enter into derivative contracts at prices that exceed our costs of production.

We are exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict such changes, our ability to mitigate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge counterparties, or some other similar proceeding or liquidity constraint, would make it unlikely we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. During periods of falling commodity prices, our derivative receivable positions increase, which increases our exposure to the counterparties. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Risks related to our operations

Drilling is an uncertain and costly activity. The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough natural gas, NGLs and oil to be commercially viable after drilling, operating and other costs. There is no way to conclusively know in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in commercially viable quantities. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of a variety of factors, including, but not limited to:

- increases in the costs, shortages or delivery delays of drilling rigs, equipment, water for hydraulic fracturing services, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in natural gas, NGLs or oil prices;
- limitations in the market for natural gas, NGLs or oil;
- facility or equipment malfunctions or operator error;
- equipment failures or accidents;
- loss of title and other title-related issues;
- pipe or cement failures and casing collapses;
- compliance with, or changes in, permitting, environmental, tax and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, and unauthorized discharges of hazardous materials;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in geological formations;
- fires, surface craterings, blowouts or explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- availability and timely issuance of required governmental permits and licenses; and
- civil unrest or protest activities.

If any of these factors were to occur, we could lose all or a part of our investment or we could fail to realize the expected benefits, either of which could materially and adversely affect our revenue and profitability. Our operations involve utilizing drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- drilling the wellbore to the full planned length;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing horizontal wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Unless we successfully replace the reserves that we produce, our reserves will decline as reserves are depleted, eventually resulting in a decrease in production and lower revenues and cash flow from operations. Our management team has specifically identified and scheduled certain drilling locations for future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, permits, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if all of the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres for which some of the drilling locations are obtained, the leases for such acreage will expire. These risks are greater at times and in areas where the pace of our exploration and development activity slows. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations and financial condition.

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies. While we have processes and procedures that we utilize to mitigate operational risks, natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids (especially those that reach surface water or groundwater), fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, geological formations with abnormal or unexpected pressures, adverse weather conditions or natural disasters and other environmental hazards and risks. In addition, our operations are sometimes near populated commercial or residential areas. If any of these hazards occur, we could sustain substantial losses as a result of:

- personal injury or loss of life;
- damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- suspension of operations by regulatory authorities; and
- repairs and remediation to resume operations.

We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We may elect not to purchase insurance in instances where we determine that the cost of available insurance is excessive relative to the risks we believe are presented. However, such determinations may prove to be incorrect. Further, some forms of insurance may become unavailable in the future. If we incur liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Additionally, we rely to a large extent on facilities owned and operated by third parties, in particular gas transportation and processing facilities, and damage to, or destruction of, those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to three third-party processing plants and connecting lines for our wells in Pennsylvania where we are insured for potential catastrophic losses from the interruption of production caused by a covered loss of or damage to the processing plants; however, such insurance is limited and may not adequately protect us from all potential consequences, damages and losses.

Our producing properties are concentrated in the Pennsylvania portion of the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic and political region. Essentially 100% of our total estimated proved reserves are located in the Appalachian Basin in Pennsylvania. We are additionally vulnerable to processing and transportation constraints for our products. We are more heavily exposed to the extensive and evolving regulatory environment in Pennsylvania which may lead to additional costs, delays or interruptions of construction, development and production from our wells. See also *The natural gas industry is subject to extensive regulation* below. Additionally, local governments in Pennsylvania are authorized to adopt and implement ordinances and impose certain restrictions regarding siting of our well sites, tank pads and other related facilities. Approval from one or more local governmental bodies, some following a public hearing, may be required before commencing construction of our facilities which can result in delay, increased expense or in some cases, prevention of development. Moreover, new initiatives or regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of substances generated by our operations, including, but not limited to, produced water, drilling fluids and other wastes associated with our operations or propose new setback distances. For example, in November 2023, Pennsylvania Governor Josh Shapiro instructed the DEP to take immediate action to pursue formal rulemakings and policy changes, including new requirements for the disclosure of chemicals used in drilling, improved control of methane emissions aligned with federal policy, stronger drilling waste protections (including inspection of secondary containment) and corrosion protections for gathering lines that transport natural gas. Currently there are a few states that have elected to ban hydraulic fracturing altogether, including Washington, New York, Maryland, Vermont and Oregon (which temporarily suspended hydraulic fracturing until 2025). Should Pennsylvania or the federal government ban hydraulic fracturing, it would preclude economic development of our Marcellus Shale reserves resulting in severe financial consequences to us.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water or dispose of or recycle water used in our operations may have a material adverse effect on our financial condition, results of operations and cash flows. Water is an essential component of our drilling and hydraulic fracturing processes. Limitation or restrictions on our ability to secure sufficient amounts of water (including limitations from natural causes such as drought) could impact our operations. If we are unable to obtain water to use in our operations from local sources, we may need to obtain it from new sources and transport the water to drilling sites, resulting in increased costs. We must either dispose of or recycle water used in our operations. Compliance with environmental and permit requirements governing the withdrawal, storage and use of recyled water, surface water or groundwater may increase costs and cause delays, interruptions or termination of our operations.

Our business depends on natural gas and oil transportation and NGLs processing facilities which are owned by others and depends on our ability to contract with those parties. Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of gathering and transportation pipeline systems, processing facilities, rail cars, trucks or vessels owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. See also above *Our producing properties are concentrated in the Pennsylvania portion of the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic and political region.* Although we have some contractual control over the transportation of our products, material changes in these business relationships, including the financial condition of the contractual counterparties, could materially affect our operations. In some cases, we do not purchase firm transportation on third-party facilities and as a result, our production transportation can be interrupted by those having firm arrangements. In other cases, we have entered into firm transportation arrangements where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. If production decreases due to reduced or delayed developmental activities, the current commodity price environment, production related difficulties or otherwise, we may be unable to utilize all of our rights under existing firm transportation contracts, resulting in obligations to pay fees without receiving revenue from sales. Such fees may be significant and may have a material adverse effect on our operations. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third-party pipelines or other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility change so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance, mechanical failures, accidents, weather and/or other reasons could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities that support our core operating area in southwest Pennsylvania could materially affect our ability to market and deliver natural gas production in that area especially if such disruption were to last for more than a short duration which could result in the necessity to curtail a significant amount of our production. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production could severely affect us due to a lack of cash flow, and if a substantial portion of the production volume is hedged at lower than market prices, our obligation to the counterparty under those financial hedges would have to be paid from borrowings thus further adversely affecting our financial condition.

Risks related to the industry in which we operate

The natural gas industry is subject to extensive regulation. Natural gas, NGLs, condensate and other hydrocarbons, as well as our operations to produce these products, are subject to extensive laws, regulations, and ordinances at the federal, state and local level. Further, new legislation, proposed rulemaking and ordinance amendments affecting the industry are under constant review for more expansive requirements and rules on our products and operations. Compliance with new and expanding laws from numerous governmental departments and agencies often increases our cost of doing business, delays our operations and decreases our profitability. Certain potential legislation, such as a ban on hydraulic fracturing, could even preclude our ability to economically develop our reserves.

Matters subject to laws and regulations affecting our business include, but are not limited to: the amount and types of substances and material that may be released into the environment, including GHGs; responding to unexpected releases of regulated substances or materials to the environment; the sourcing and disposal of water used in the drilling and completions process; permits, performance rules and reporting obligations concerning drilling, completion and production operations; threatened or endangered species and waterway protection efforts; and climate related initiatives.

Environmental regulations and pollution liability could expose us to significant costs and penalties. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies or initiatives. Some of these environmental laws and regulations may impose strict, joint and several liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred, or conditions caused by prior owners or operators or which relate to third party sites where we have taken materials for recycling or disposal. Pennsylvania law also imposes criminal liability for certain releases of substances, regardless of fault or intent. Failure to comply with these laws and regulations may result in the occurrence of delays, cancellations or restrictions in permitting or performance of our projects or other operations and subject us to administrative, civil and/or criminal penalties, corrective actions and orders enjoining some or all of our operations. Our operations may be impacted by new and amended laws and regulations and reinterpretations of existing laws and regulations or increased government enforcement relating to environmental laws. For example, properly handled drilling fluids and produced water are currently exempt from regulation as hazardous waste under RCRA, and instead are regulated under RCRA's non-hazardous waste provisions. It is possible that the EPA may in the future propose rulemaking that designates such wastes as hazardous rather than non-hazardous, and a similar designation may be made at the state level. Should this occur at the federal and/or state level it could result in significant costs to attain and maintain compliance.

We may also be exposed to liability and costs for handling of hydrocarbons, air emissions and wastewater or other fluid discharges related to our operations and waste disposal practices. Spills or other unauthorized releases of hazardous or regulated substances by us, our contractors or resulting from our operations could expose us to material losses, expenditures and liabilities, civil and criminal liabilities, under environmental laws and regulation and we are currently and have in the past been involved in such investigations, remediation and monitoring activities. The Pennsylvania Office of the Attorney General has publicly announced investigations and charges generally related to our industry in Pennsylvania. Additionally, neighboring landowners and other third parties may assert claims or file lawsuits against us for personal injury and/or property damage allegedly caused by the release of substances into the environment, with or without evidence of an impact from our operations, all of which could also result in significant litigation or settlement costs as well as reputational harm.

Laws and regulations pertaining to threatened and endangered species and protection of waterways could delay or restrict our operations and cause us to incur substantial costs. Various federal and state statutes prohibit actions or operations that adversely affect endangered or threatened species and their habitats. These statutes include the federal Endangered Species Act of 1973 ("ESA"), the Migratory Bird Treaty Act, the CWA, CERCLA and similar state programs. The United States Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in material restrictions to land use and delay, restrict or even prevent our operations. The Biden administration has taken action to broaden enforcement under ESA, including expanding the definition of critical habitat. While none of the species listed by FWS as threatened or endangered materially affect our operations at the present time, the future designation of previously unprotected species as threatened or endangered in areas where we conduct our operations or expansion of areas designated as critical habitat could cause us to incur increased costs arising from species protection measures and/or limit or prevent our ability to operate which could have an adverse effect on our ability to develop and produce reserves.

Additionally, operations may be impacted by the existence of wetlands or other environmentally sensitive areas based upon the scope of the CWA and its protection of waters of the United States. On December 30, 2022, the EPA announced a final rule related to a revised definition of waters of the United States that included a broader interpretation similar to the pre-2015 definition. However, on May 5, 2023, the Supreme Court issued a landmark ruling in *Sackett* v. EPA significantly narrowing the scope of the EPA's definition of the "waters of the United States". The EPA subsequently published a new final rule on September 8, 2023 defining "waters of the United States" to conform to the Supreme Court's ruling in *Sackett*, thereby narrowing the scope of federal jurisdiction under the CWA. The EPA may change its rules in the future. To the extent that legal challenges or any further rulemaking expands the CWA’s jurisdiction we could incur increased costs and restrictions, and/or delays or cancellations in permitting or projects, which could result in significant costs and liabilities or financial losses.

Climate related regulations and initiatives could expose us to significant costs and restrictions on operations. There is an ongoing public debate as to the extent to which our climate is changing, the potential causes of climate change and its potential impacts. As part of that debate, there is also general belief that increased levels of GHGs, including carbon dioxide and methane, have contributed to and continue to contribute to climate change which has led to numerous regulatory, political, litigation and financial risks associated with the production of fossil fuels and emissions of GHGs. Our operations result in GHGs.

Federal and state governments have from time to time considered legislation and regulations to reduce GHG emissions, including, but not limited to the implementation of GHG monitoring and reporting for the natural gas industry which includes certain of our operations. The EPA has sought to achieve these reductions under the Clean Air Act and the NSPS aimed at volatile organic compounds ("VOCs") including methane emissions from oil and natural gas sources. On December 2, 2023, the EPA released a copy of its final rule on NSPS to sharply reduce emissions of methane and other air pollution from oil and natural gas operations. The final rule will, among other things (i) require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time, (ii) phase out routine flaring from new natural gas wells (iii) require the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies, (iv) leverage data collected by certified third parties to identify and address "super emitting" sources and eliminate or minimize emissions from common pieces of equipment used in oil and gas operations such as process controllers, pumps and storage tanks and (v) require documentation that wells are properly closed and plugged before monitoring is allowed to end. In response to feedback received during the comment period, the EPA adjusted several provisions of this proposed rule to allow extended time for compliance, including a two-year phase-in period for eliminating routine flaring of natural gas that is emitted from new oil wells. Additional costs are likely to result from compliance with the final rule based on expanded monitoring requirements and more stringent emissions limits. Additionally, the EPA proposed rules pursuant to the 2022 Inflation Reduction Act that would charge a fee associated with certain levels of methane emissions. In Pennsylvania, regulators have implemented operating permits and restrictions on emissions for well site operations, compressors, processing plants and other downstream facilities that directly impact our operations. The DEP is implementing new and additional regulations to limit VOCs from existing sources for the oil and gas industry. There have also been a number of state and regional efforts that have emerged that seek to track and reduce GHG emissions by means of cap and trade programs where emitters would be required to acquire and surrender emission allowances in return for emitting GHGs. In September 2020, the PEQB approved a draft resolution to enter the Regional Greenhouse Gas Initiative ("RGGI"), a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont to cap and reduce power sector CO_2 emissions from fossil-fuel-fired electric power plants. However, in response to the PEQB's resolution to join the RGGI, the Pennsylvania General Assembly adopted a resolution on December 15, 2021, expressing its disapproval of the state's efforts to enroll in RGGI, stating that the RGGI would drive up energy costs and result in thousands of lost jobs. On January 10, 2022, former Governor Wolf vetoed the disapproval resolution. In April 2022, the Pennsylvania senate failed to override former Governor Wolf's veto and as a result, Pennsylvania officially joined the RGGI. However, in July 2022, the Commonwealth Court of Pennsylvania issued an order blocking the state from participating in the RGGI until the court ruled on its constitutionality. On November 1, 2023, the Pennsylvania Commonwealth Court ruled that funds generated through the RGGI are an unconstitutional tax, effectively preventing the state from participating in RGGI. Pennsylvania Governor Josh Shapiro appealed that decision to the state's Supreme Court. Moreover, in 2023, Pennsylvania Governor Josh Shapiro created the "RGGI Working Group" and tasked them with measuring RGGI or an alternative against a three-part test: protect and create energy jobs, take real action to address climate change, and ensure reliable, affordable power for consumers in the long-term. While the RGGI Working Group agreed that a cap-and-trade regulation would meet these goals, they did not conclude that RGGI is the correct program for Pennsylvania, citing wider concerns regarding increased energy costs and job loss. The RGGI Working Group gave Governor Shapiro a list of recommendations in a four-page memo, suggesting, among other things, Governor Shapiro explore a cap-and-trade program that includes Washington, D.C. and 13 states whose electric grids are run by PJM Interconnection, while encouraging the PJM-run states to reach consensus on carbon trading. To date, Governor Shapiro has not taken any official action in response to the RGGI Working Group's recommendations. In the absence of participation in the RGGI, the DEP is evaluating other regulations to achieve the emissions reductions. We have initiated our own internal goals to reduce GHG emissions from our operations. For example, setting a goal of net zero Scope 1 and 2 GHG emissions by 2025; however, there are a variety of factors that may prevent us from meeting that goal including but not limited to operational malfunctions, availability of equipment and services, engineering results, capital constraints and availability and success of carbon offsetting initiatives. Given uncertainties related to the use of emerging technologies, the state of markets for, and the validity and availability of verified carbon offsets along with the uncertainty of emission measurement calculations, we cannot predict whether or not we will be able to timely meet our net zero GHG emissions goal. We continue to evaluate a range of technology and other measures, such as carbon offsets, that could assist with meeting this goal. Failure or a perception (whether or not valid) of failure to meet our GHG emissions goals, could damage our reputation and negatively impact our stock price.

The outcome of federal, state and regional actions to address global climate change could result in a variety of new laws and regulations to control or restrict emissions including taxes or other charges to deter or restrict emissions of GHGs. This may also depend upon political outcomes as there have been certain candidates seeking election to various state and federal offices or their appointees, who have made pledges to restrict GHG emissions, ban hydraulic fracturing of oil and natural gas wells and ban new leases for production of oil and natural gas on federal lands. Our reserves development is critically dependent upon the use of hydraulic fracturing and we cannot economically develop any of our reserves without using such technology (which we believe has been safely conducted for many decades) and a ban of such technology could result in severe economic harm to us.

There are also increasing litigation risks associated with climate change concerns as a number of cities and local governments have initiated lawsuits against fossil fuel producers in state and federal court asserting claims for public nuisance and seeking damages for climate change impacts to roadways and infrastructure. Such lawsuits have also alleged that fossil fuel producers have been aware of the adverse effects of climate change and defrauded their investors by failing to adequately disclose those impacts.

Financial risks for fossil fuel energy companies, including natural gas producers, are also on the rise as stockholders and bondholders concerned about the potential effects of fossil fuels on climate change may elect to shift some or all of their investments away from fossil fuel based energy. Institutional lenders who provide financing to fossil fuel energy companies also have been under pressure from activists and are the subject of lobbying to not provide funding for fossil fuel production. Also, in November 2021, the Federal Reserve issued a statement in support of the efforts of the Network of Greening the Financial System, of which the Federal Reserve is a member, to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Some of these institutional lenders may elect not to provide funding for us which could result in restriction, delay or cancellation of drilling programs or development or production activities or impair our ability to operate economically.

On March 21, 2022, the SEC issued a proposed rule regarding the enhancement and standardization of mandatory climate-related disclosures. The proposed rule would require registrants to include certain climate-related disclosures in their registration statements and periodic reports. The SEC is expected to release the final rule in April of 2024. While the final form and substance of these requirements are not yet known and the ultimate scope and impact on our business is uncertain, compliance with the proposed rule may result in increased legal, accounting, operational, technology and financial compliance costs.

Certain organizations that provide corporate governance and other corporate risk information to investors and stockholders have developed scores and ratings to evaluate companies and investment funds based on sustainability or environmental, social and governance ("ESG") metrics. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and stockholders. A number of advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through investment and voting practices of investment advisors, public pension funds, universities and other members of the investing community. As a result, many investment funds focus on positive ESG business practices and sustainability scores when making investments. Companies which do not adapt to or comply with investor or stockholder ESG expectations and standards or which are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the financial condition, results of operations or cash flows of such a company could be materially and adversely affected.

Moreover, we may from time-to-time create and publish voluntary disclosures regarding ESG matters. Many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

At this time, we cannot predict the potential impact of such laws, regulations, regional or international initiatives or compacts, litigation, ESG ratings or financing restrictions due to climate concerns on our future consolidated financial condition, results of operations or cash flows; however, such impacts could be material and have material negative consequences to our business.

Information concerning our reserves and future net cash flow are estimates and are not certain to match our results. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves depend on many assumptions relating to current and future economic conditions and commodity prices as well as the projected productivity of our wells and infrastructure to gather, process, store and/or transport our products to market. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we utilize robust processes and procedures to evaluate and estimate our reserves, they are estimates and the actual production, revenues and costs to develop our estimated reserves will vary from estimates and these variances could be material and/or negative.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective application of engineering principles to natural gas, NGLs and oil reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of natural gas, NGLs and oil production;
- the revenues and costs associated with that production;
- the amount and timing of future development expenditures; and
- future commodity prices.

The discounted future net cash flows from our proved reserves included in this report are not the same as the market value of the reserves attributable to our properties. As required by United States generally accepted accounting principles ("U.S. GAAP"), the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (first day of the month) while cost estimates are based on current year-end economic conditions. Actual future prices and costs may be materially higher or lower. In addition, the ten percent discount factor that is required to be used to calculate discounted future net cash flows for reporting purposes under U.S. GAAP is not necessarily the most appropriate discount factor based on the cost of capital, which varies from time to time, and risks associated with our business and the oil and gas industry in general.

We may face various risks associated with the long-term trend toward increased activism against oil and gas exploration and development activities. Opposition toward oil and gas drilling and development activity has been growing over time. Companies in the oil and gas industry are often the target of activist efforts to delay or prevent oil and gas development from both individuals and non-governmental organizations who use safety, environmental compliance and business practices to support their opposition to oil and gas drilling. Anti-development activists are working to, among other things, reduce access to federal and state government lands, delay or cancel certain projects such as the development of oil and gas drilling or export facilities, as well as the pipeline infrastructure needed to transport and process oil and gas production. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling and hydraulic fracturing in the United States, even in jurisdictions like Pennsylvania that are among the most stringent in their regulation of the industry. Such activist efforts could result in the following:

- delay or denial of drilling permits;
- restrictions on or prevention of installation or operation of production, gathering or processing facilities;
- restrictions on or prevention of the use of certain operating practices, such as hydraulic fracturing, or the disposal of related materials, such as hydraulic fracturing fluids and produced water;
- additional regulatory burdens;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

We may incur significant costs associated with responding to these initiatives and such actions may materially adversely affect our financial results. Complying with any resulting additional legal or regulatory requirements that are substantial or prevent our activity could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Conservation measures and technological advances could reduce demand for oil and natural gas. Fuel conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation or storage devices (such as battery technology) may in the future, reduce the demand for and, in turn the prices of, natural gas, NGLs and oil that we sell. In addition, these measures may reduce the availability to us of necessary third-party services and facilities that we rely on which could increase our operational costs and adversely impact our ability to produce, transport and process natural gas, NGLs and oil. The impact of changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Legal, tax and regulatory risks

U.S. or state tax legislation may adversely affect our business, results of operations, financial condition and cash flow . Legislation is periodically proposed that could make significant changes to United States federal income tax laws and could include the elimination of certain United States federal income tax benefits currently available to oil and gas exploration and production companies including, but not limited to, (i) the repeal of percentage depletion allowances for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs and; (iii) an extension of the amortization period for certain geological and geophysical expenditures. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced consumer demand for our products. The passage of any such legislation or any other similar change in United States federal income tax law could increase costs or eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development and any such changes could have an adverse effect on our financial condition, results of operations and cash flows.

In 2022, legislation commonly known as the Inflation Reduction Act was signed into law, which includes, among other things, a corporate alternative minimum tax (the "CAMT") and a one percent excise tax on corporate stock repurchases. The CAMT generally treats a corporation as an applicable corporation in any taxable year in which the average annual adjusted financial statement income for a three taxable-year period ending prior to such taxable year exceeds $1.0 billion. If we become subject to CAMT, our cash obligations for U.S. federal income taxes could be significantly accelerated. To the extent the 1% excise tax applies to repurchases of shares under our common stock repurchases program, the number of shares we repurchase and our cash flow may be affected.

In 2012, Pennsylvania enacted legislation creating a tax referred to as the natural gas impact fee applicable to production in Pennsylvania, where all of our acreage is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. Much like a severance tax, the fee is on a sliding scale set by the Pennsylvania Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices on the last day of each month. The impact fee increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed. From time to time, the Pennsylvania Governor and various Pennsylvania state lawmakers have proposed legislation to enact a severance tax in substitution for, or as an addition to, the impact fee already in place. The structure of and ultimate effect of any additional tax burden cannot be estimated at this time but could be material.

Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition. Like many oil and gas companies, we are involved in various legal proceedings, including threatened claims, such as title, royalty, and contractual disputes. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting judgment against us in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact our cash flows, operating results and financial condition. Judgments and estimates to determine accruals or range of losses related to legal proceedings could change from one period to the next, and such changes could be material. Current accruals may be insufficient to satisfy any such judgments. Legal proceedings could also result in negative publicity about Range. In addition, legal proceedings distract management and other personnel from their primary responsibilities. At this time, based on the information available to management, there are no pending claims or litigation which appear likely to result in a material financial impact. However, management's assessment of pending claims and litigation could be inaccurate and subsequent events could result in material liabilities from such claims or litigation.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel. None of our senior management team nor any of the other officers are subject to an employment agreement and therefore retaining them as employees is less certain than if they were parties to an employment agreement. The unanticipated loss of one or more of these individuals could have a material adverse effect on our business. Further, the loss of key technical professionals with extensive experience in our core operating area could be difficult to replace if they were to leave and the loss of such employees could adversely affect the costs of drilling, completing and operating our wells.

Risks related to our common stock

Common stockholders may be diluted if additional shares are issued. In order to align interests and encourage ownership, we issue restricted stock and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional senior notes or other securities or debt convertible into common stock to extend maturities or fund capital expenditures, including acquisitions. The issuance of additional shares of common stock results in dilution of the interests of existing stockholders. One way to reverse the effects of dilution is by the acquisition of our stock. On December 31, 2023, our share repurchase program has $1.1 billion remaining. However, this program may be suspended, modified or discontinued by the board of directors at any time.

Dividend limitations. Limits on the payment of dividends and other restricted payments (as defined in our bank credit facility) are imposed under our bank credit facility. These limitations may, in certain circumstances, limit or prevent the payment of dividends.

Our stock price may be volatile and stockholders may not be able to resell shares of our common stock at or above the price they paid. The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2021 to December 31, 2023, the price of our common stock reported by the New York Stock Exchange ranged from a low of $6.78 per share to a high of $37.88 per share. We expect our stock price to continue to be subject to volatility as a result of a variety of factors, including factors beyond our control. These factors include:

- most significantly, changes in natural gas, NGLs and oil prices;
- variations in drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation and/or taxation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- expectations regarding our capital program, including any determination by our board of directors regarding repurchasing stock or paying dividends;
- changes in key personnel; or
- future sales of additional stock and changes in our capital structure.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

General risk factors

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions. The United States government has issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats. As a natural gas and oil producer, we face various security threats, including:

- cybersecurity threats to gain unauthorized access to sensitive information or to render data or computer systems unusable;
- threats to the security or operations at our physical facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; or
- threats from terrorist acts or other geopolitical events.

Digital technologies are an integral part of our business and are used to support our exploration, development and production activities and our key accounting and financial reporting functions. We use these systems to analyze and store financial and operating data and to communicate internally and with outside business counterparties. Cyberattacks could compromise our core infrastructure and digital technologies and result in disruptions to our business operations or the loss of our data and proprietary information. In addition, digital technologies control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A cyberattack against these operating systems, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, cause accidental discharge and/or make it difficult or impossible to accurately account for production and settle transactions. A cyberattack on a vendor or a service provider could result in supply chain disruptions, which could delay or halt development projects. A cyberattack on our accounting or human resources systems could expose us to liability if personal information is obtained. Furthermore, the shift to a hybrid systems model including on-premises and cloud environments has transformed how systems interconnect, how data is stored, how users interact with applications and what end user devices are utilized. This shift has resulted in additional cybersecurity risk.

Security threats have subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to harm to our employees or losses of sensitive information, losses of critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, and results of operations or cash flows. Attackers are becoming more sophisticated and both the frequency and magnitude of cyberattacks in particular are expected to increase and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data, 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. These events could damage our reputation and lead to financial losses from unauthorized disbursement of funds, remedial actions, loss of business and/or potential liability. We may be unable to anticipate, detect or prevent future attacks, particularly as methodologies utilized by attackers change frequently and are not recognized until launched. Additionally, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, which could require us to expend significant additional resources to meet such requirements. While we utilize extensive processes and procedures that we deem appropriate to counter cybersecurity risks and to date have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future. Any losses, costs or liabilities directly or indirectly related to cyberattacks or similar incidents may not be covered by, or may exceed the coverage limits of, any of our insurance policies.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in areas around the world and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism and, in turn, could materially and adversely affect our business and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We have a comprehensive approach to mitigate cybersecurity risk which primarily focuses on three key elements:

- People - security awareness education and readiness-testing throughout the year for employees and contractors;
- Process - incorporating "cyber awareness" in our day-to-day processes which includes constant review of alerting and detection to mitigate constant cybersecurity threats, regular review of security posture and security roadmap to ensure alignment throughout the organization, physical and digital asset protection and security vulnerability remediation via preventable and detective measures; and
- Technology - investing in industry aligned security technology and threat intelligence capabilities.

Cybersecurity governance is supported by our information technology department which includes certified security professionals and seasoned security analysts. This department conducts an extensive periodic review of our security initiatives to assess the current state of our program (using a cybersecurity framework) and potential evolution based on current business risks along with detection and communication of cybersecurity threats and actions to mitigate those threats. Cybersecurity incidents meeting a pre-determined minimum threshold are communicated to a separate committee comprised of officers charged with reporting responsibilities to determine overall materiality and disclosure obligations.

We have engaged an independent third-party operations center that is focused on, among other things, monitoring alerts, logs, behavior analytics and end devices usage. This continuous monitoring is in conjunction with periodic security assessments, constant vulnerability scanning and frequent penetration tests. We also complete an initial vendor cybersecurity review process for new cloud-based software which provides a standardized review assessment. We monitor known third-party breaches, known software vulnerabilities that may affect third-party vendors and communicate as necessary with those vendors allowing us to increase security of our technology assets and our data.

Our board of directors oversees our cybersecurity risk and receives a quarterly cybersecurity report and an update from management which includes additional discussions of any relevant issues related to the understanding of technology and cybersecurity risk that may be relevant at any given time. This report includes, among other things, information regarding our current security posture and on-going cybersecurity events. Cybersecurity incidents meeting a pre-determined minimum threshold are communicated to our Board.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of, or party to, a number of pending or threatened legal actions, administrative proceedings or investigations arising in the ordinary course of our business including, but not limited to royalty claims, contract claims and environmental claims. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to these actions, proceedings or investigations will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then-current status of litigation.

Environmental Proceedings

From time to time, we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $250,000.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC". During 2023, trading volume averaged approximately 3.7 million shares per day.

Holders of Record

Pursuant to the records of our transfer agent, as of February 19, 2024, there were approximately 846 holders of record of our common stock.

Dividends

The payment of dividends is subject to the formal declaration by the board of directors. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board of directors and will depend upon, among other things, our earnings, financial condition, capital requirements, levels of indebtedness and other considerations our board of directors deems relevant. For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Equity Compensation Plan Information

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2023.

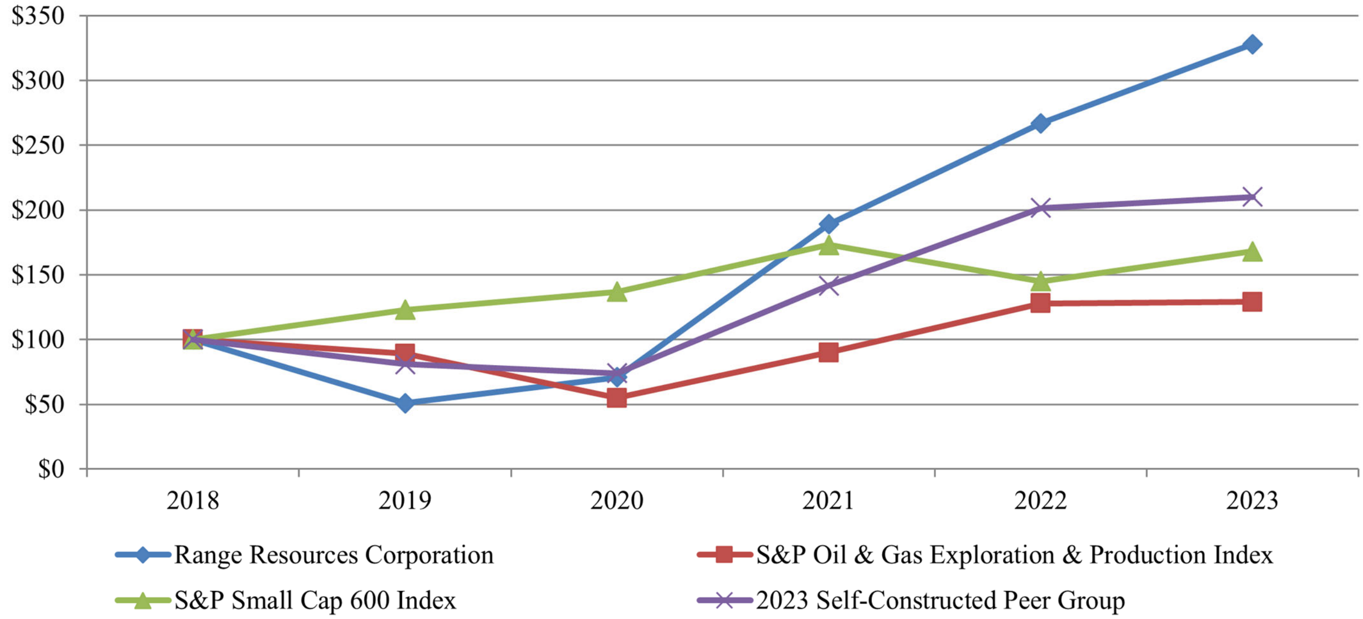
Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In 2019, our board of directors authorized a $100 million common stock repurchase program. In 2022, our board of directors increased the authorization under the program. As of December 31, 2023, these repurchased shares are held as treasury stock and we have approximately $1.1 billion of remaining authorization under the program. Purchases of our common stock in fourth quarter 2023 were as follows:

	Three Months Ended December 31, 2023			
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased Under Plans or Programs
October 2023	50,000	$ 29.84	50,000	$ 1,089,244,444
November 2023	—	$ —	—	$ 1,089,244,444
December 2023	265,000	$ 29.74	265,000	$ 1,081,359,316
	315,000		315,000	

Stockholder Return Performance Presentation

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the S&P Oil and Gas Exploration and Production Index, the S&P Small Cap 600 Index and a customized peer group which matches the peer group selected by our compensation committee of the board of directors which is used in our performance unit program. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2018 and that dividends were reinvested.



	2018	2019	2020	2021	2022	2023
Range Resources Corporation	$ 100	$ 51	$ 71	$ 189	$ 267	$ 328
S&P Oil & Gas Exploration & Production Index	100	89	55	90	128	129
S&P Small Cap 600 Index	100	123	137	173	145	168
2023 Self-Constructed Peer Group (a)	100	81	74	142	202	210

(a) The 2023 Self-Constructed Peer Group includes the following twelve companies: Antero Resources Corporation, Chesapeake Energy Corporation, CNX Resources, Comstock Resources, Inc., Coterra Energy, Inc., EQT Corporation, Matador Resources, Murphy Oil, PDC Energy (included through August 2023 when it was acquired by Chevron Corp.), SM Energy Company, Southwestern Energy Company and the S&P 500 index and is weighted based on stock market capitalization.

ITEM 6. RESERVED

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition and should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and other financial information found elsewhere in this Form 10-K. See also matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements."

The following tables and discussions set forth key operating and financial data for the years ended December 31, 2023 and 2022. For similar discussions of the year ended December 31, 2022 compared to December 31, 2021 results, refer to Item 7. "Managements' Discussion and Analysis of Financial Condition and Results of Operations" under Part II of our annual report on Form 10-K for the year ended December 31, 2022, which was filed with the SEC on February 27, 2023.

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs,") crude oil and condensate company engaged in the exploration, development and acquisition of natural gas and crude oil properties located in the Appalachian region of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our overarching business objective is to build stockholder value through returns-focused development of natural gas properties. Our strategy to achieve our business objective is to generate consistent cash flows from reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions and divestitures of non-core or, at times, core assets. Currently, our investment portfolio is focused on high quality natural gas assets in the state of Pennsylvania. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves.

Commodity prices have been and are expected to remain volatile. We believe we are well-positioned to manage any challenges during a low commodity price environment and that we can endure the continued volatility in current and future commodity prices by:

- exercising discipline in our capital investments;
- optimizing drilling, completion and operational efficiencies;
- maintaining a competitive cost structure;
- managing price risk through the hedging of our production; and
- managing our balance sheet.

Prices for natural gas, NGLs, crude oil and condensate fluctuate widely and affect:

- our revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil that we can economically produce;
- the quantity of natural gas, NGLs and oil shown as proved reserves;
- the amount of cash flow available to us for reinvestment; and
- our ability to borrow and raise additional capital.

We prepare our financial statements in conformity with U.S. GAAP, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

Key 2023 highlights include:

Financial and operating results:

- We recorded net income of $871.1 million for the year ended December 31, 2023;
- Average daily production was 2.14 Bcfe during the year;
- Repurchased 715,000 shares of common stock via the share repurchase program leaving $1.1 billion available under the repurchase program;
- Paid dividends of $77.2 million, ending the year with $212.0 million in cash on hand; and
- Executed opportunistic debt repurchases of $61.6 million in the open market.

Corporate sustainability highlights and initiatives:

- Completed the MiQ certification for our Southwest Pennsylvania assets and earned an "A" grade;
- Continued to recycle approximately 100% of our produced water;
- Implemented the use of compressed air pneumatic controllers;
- Achieved a 28% reduction in number of workforce recordable injuries (both employee and contractor) with a Total Recordable Incident Rate of 0.34;
- Achieved a 70% reduction in preventable vehicle incidents with six incidents in 2023; and
- Continued board of directors refreshment through the appointment of one new director.

Management's Discussion and Analysis of Results of Operations

Commodity prices have remained volatile. Benchmarks for natural gas, oil and NGLs decreased in 2023 compared to 2022 and, as a result, we experienced significant decreases in our price realizations when compared to the same period of 2022. Despite lower prices, we continued to focus on creating long-term value for our stockholders along with positioning ourselves to be a responsible and reliable supplier of natural gas.

Overview of 2023 Results

During 2023, we recognized net income of $871.1 million, or $3.57 per diluted common share compared to $1.2 billion, or $4.69 per diluted common share during 2022. The decrease in net income for the year ended December 31, 2023 when compared to 2022 is primarily due to significantly lower realized prices.

For the year ended December 31, 2023, we experienced a decrease in revenue from the sale of natural gas, NGLs and oil due to a 41% decrease in net realized prices (average prices including all derivative settlements and third-party transportation costs paid by us) when compared to 2022. Daily production in 2023 averaged 2.14 Bcfe compared to 2.12 Bcfe in 2022.

During 2023, our financial and operating performance included the following results:

- revenue from the sale of natural gas, NGLs and oil decreased 52% from the same period of 2022 with a 53% decrease in average realized prices (before cash settlements on our derivatives) partially offset by slightly higher production volumes;
- revenue from the sale of natural gas, NGLs and oil (including cash settlements on our derivatives) decreased 30% from the same period of 2022;
- transportation, gathering, processing and compression expense per mcfe was $1.43 in 2023 compared to $1.61 in the same period of 2022 primarily due to the impact of lower commodity prices;
- direct operating expense per mcfe was $0.12 in 2023 compared to $0.11 in the same period of 2022 due to higher workover costs;
- general and administrative expense per mcfe for 2023 decreased 5% from the same period of 2022 due to lower stock-based compensation;
- interest expense per mcfe for 2023 decreased 24% from the same period of 2022 due to lower debt balances;
- our DD&A rate per mcfe for 2023 decreased 2% from the same period of 2022;
- drilled 47.4 net wells with a 100% success rate;
- cash flow from operating activities for 2023 was 48% lower than the same period of 2022 due to lower commodity prices; and
- our capital budget spending for 2023 was $613.6 million, which was within our initially announced range of $570.0 million to $615.0 million.

The year ended December 31, 2023 also included the following highlights to enhance our balance sheet, return capital to investors and preserve liquidity:

- paid $77.2 million in dividends or $0.32 per share compared to $0.16 in 2022;
- repurchased $19.0 million of our common stock compared to $399.7 million in 2022;
- repurchased in the open market $61.6 million face value of our 4.875% senior notes due 2025 at a discount; and
- enhanced liquidity with the accumulation of cash on hand of $212.0 million along with $1.3 billion available under our credit facility.

We generated $977.9 million of cash from operating activities in 2023, a decrease of $886.9 million from 2022 which reflects significantly lower realized prices partially offset by lower comparative working capital outflows.

Acquisitions

During 2023, we invested $40.1 million to acquire unproved acreage compared to $28.7 million in 2022. We continue selective acreage leasing and lease renewals to consolidate our acreage positions in the Marcellus Shale play in Pennsylvania.

2024 Outlook

As we enter 2024, we believe we are positioned for sustainable long-term success. For 2024, we expect our capital budget to be in the range of $620 million to $670 million for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. We expect our 2024 capital budget to achieve production similar to our 2023 production. Our 2024 capital budget is focused on continuing to improve corporate returns and generating free cash flow. We expect it to be funded with operating cash flow. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2024 is partially mitigated by entering into commodity derivative contracts and we intend to continue to enter into these types of contracts. We believe it is likely that commodity prices will continue to be volatile during 2024.

Market Conditions

We believe we are positioned for sustainable long-term success. We continue to monitor the impact of the actions of OPEC and other large producing nations, the Russia-Ukraine conflict, hostilities in the Middle East, global inventories of oil and gas, future monetary policy and governmental policies aimed at transitioning towards lower carbon energy and we expect prices for some or all of the commodities we produce to remain volatile given the complex dynamics of supply and demand that exist in the global market. In fourth quarter 2023, natural gas prices declined based on the relatively mild early days of winter and delays to a large liquefied natural gas export project in-service date. Longer term natural gas futures prices have remained stronger based on market expectations that associated gas-related activity in oil basins and dry gas basin activity will show modest rates of growth compared with the past due to infrastructure constraints, capital discipline and core inventory exhaustion. In addition, the global energy crisis further highlighted the low cost and low emissions shale gas resource base in North America, supporting continued strong structural demand growth for United States liquefied natural gas exports, domestic industrial gas demand and power generation. Other factors such as geopolitical disruptions, supply chain disruptions, cost inflation, concerns over a potential economic recession and the pace and extent of tightening global monetary policy may impact the demand for oil, natural gas and NGLs. We continue to assess and monitor the impact and consequences of these factors on our operations.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. Recently, natural gas prices have decreased, when compared to December 2023, with the average NYMEX monthly settlement price for natural gas decreasing to $2.49 per mcf for February 2024 with the recent mild winter weather. Crude oil prices have increased, when compared to December 2023, to $73.86 per barrel in January 2024. The following table lists related benchmarks for natural gas, oil and NGLs composite prices for the years ended December 31, 2023 and 2022.

	Year Ended December 31,	
	2023	2022
Benchmarks:		
Average NYMEX prices [(a)]		
Natural gas (per mcf)	$ 2.75	$ 6.64
Oil (per bbl)	$ 77.54	$ 94.90
Mont Belvieu NGLs composite (per gallon) [(b)]	$ 0.56	$ 0.90

(a) Based on average of monthly last day settlement prices on the New York Mercantile Exchange ("NYMEX").

(b) Based on our estimated NGLs product composition per barrel.

Our price realizations (not including the impact of our derivatives) may differ from the benchmarks for many reasons, including quality, location, or production being sold at different indices.

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. In 2023, natural gas, NGLs and oil sales decreased 52% from 2022 with a 53% decrease in realized prices (excluding cash settlements on our derivatives) partially offset by slightly higher production volumes. The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for the last two years (in thousands):

	Year Ended December 31,			
	2023	2022	Change	% Change
Natural gas, NGLs and Oil sales				
Natural gas	$ 1,234,308	$ 3,364,111	$ (2,129,803)	(63%)
NGLs	933,791	1,308,574	(374,783)	(29%)
Oil and condensate	166,562	238,407	(71,845)	(30%)
Total natural gas, NGLs and oil sales	$ 2,334,661	$ 4,911,092	$ (2,576,431)	(52%)

Production is maintained through drilling success as we place new wells on production which is partially offset by the natural decline of our natural gas and oil reserves through production. Our production for the last two years is set forth in the following table:

	Year Ended December 31,			
	2023	2022	Change	% Change
Production [(a)]				
Natural gas (mcf)	538,084,671	539,442,624	(1,357,953)	—%
NGLs (bbls)	37,939,700	36,392,033	1,547,667	4%
Crude oil and condensate (bbls)	2,475,306	2,715,681	(240,375)	(9%)
Total (mcfe) [(b)]	780,574,707	774,088,908	6,485,799	1%
Average daily production [(a)]				
Natural gas (mcf)	1,474,205	1,477,925	(3,720)	—%
NGLs (bbls)	103,944	99,704	4,240	4%
Crude oil and condensate (bbls)	6,782	7,440	(658)	(9%)
Total (mcfe) [(b)]	2,138,561	2,120,792	17,769	1%

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) received during 2023 was $1.88 per mcfe compared to $3.17 per mcfe in 2022. The majority of our production is sold at market-sensitive prices. Generally, if the related commodity index declines, the price we receive for our production will also decline. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices should include the impact of transportation, gathering, processing and compression expense. Average sales prices (excluding derivative settlements) do not include any derivative settlements or third-party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of income. Average sales prices (excluding derivative settlements) do include transportation costs where we receive net proceeds from the purchaser. Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) calculation includes all cash settlements for derivatives. Our derivative settlements included in our realized price calculations do not include settlements of contingent consideration related to the sale of our North Louisiana properties. Average realized price calculations for the last two years are shown below:

	Year Ended December 31,			
	2023	2022	Change	% Change
Average Prices				
Average sales prices (excluding derivative settlements):				
Natural gas (per mcf)	$ 2.29	$ 6.24	$ (3.95)	(63%)
NGLs (per bbl)	24.61	35.96	(11.35)	(32%)
Crude oil (per bbl)	67.29	87.79	(20.50)	(23%)
Total (per mcfe) [(a)]	2.99	6.34	(3.35)	(53%)
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$ 2.77	$ 4.16	$ (1.39)	(33%)
NGLs (per bbl)	24.61	35.62	(11.01)	(31%)
Crude oil (per bbl)	62.77	57.39	5.38	9%
Total (per mcfe) [(a)]	3.31	4.78	(1.47)	(31%)
Average realized prices (including all derivative settlements and third-party transportation costs paid by Range):				
Natural gas (per mcf)	$ 1.68	$ 2.90	$ (1.22)	(42%)
NGLs (per bbl)	10.80	20.08	(9.28)	(46%)
Crude oil (per bbl)	62.43	57.39	5.04	9%
Total (per mcfe) [(a)]	1.88	3.17	(1.29)	(41%)

(a) Oil and NGLs volumes are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Realized prices include the impact of basis differentials and gains or losses realized from our basis hedging. The prices we receive for our natural gas can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors. The following table provides this impact on a per mcf basis:

	Year Ended December 31,	
	2023	2022
Average natural gas differentials below NYMEX	$ (0.46)	$ (0.40)
Realized gains on basis hedging	$ 0.05	$ 0.11

The following tables reflect our production and average realized commodity prices (excluding derivative settlements and third-party transportation costs paid by Range) (in thousands, except prices):

	Year Ended December 31,			
	2022	Price Variance	Volume Variance	2023
Natural gas				
Price (per mcf)	$ 6.24	$ (3.95)	$ —	$ 2.29
Production (Mmcf)	539,443	—	(1,358)	538,085
Natural gas sales	$ 3,364,111	$ (2,121,335)	$ (8,468)	$ 1,234,308

	Year Ended December 31,			
	2022	Price Variance	Volume Variance	2023
NGLs				
Price (per bbl)	$ 35.96	$ (11.35)	$ —	$ 24.61
Production (Mbbls)	36,392	—	1,548	37,940
NGLs sales	$ 1,308,574	$ (430,434)	$ 55,651	$ 933,791

	Year Ended December 31,			
	2022	Price Variance	Volume Variance	2023
Crude oil				
Price (per bbl)	$ 87.79	$ (20.50)	$ —	$ 67.29
Production (Mbbls)	2,716	—	(241)	2,475
Crude oil sales	$ 238,407	$ (50,742)	$ (21,103)	$ 166,562

	Year Ended December 31,			
	2022	Price Variance	Volume Variance	2023
Consolidated				
Price (per mcfe)	$ 6.34	$ (3.35)	$ —	$ 2.99
Production (Mmcfe)	774,089	—	6,486	780,575
Total natural gas, NGLs and oil sales	$ 4,911,092	$ (2,617,579)	$ 41,148	$ 2,334,661

Transportation, gathering, processing and compression expense was $1.1 billion in 2023 and $1.2 billion in 2022. These third-party costs are lower than the prior year due to lower fuel and lower electricity costs along with the impact of lower NGLs prices which results in lower processing costs. We have included these costs in the calculation of average realized prices (including all derivative settlements and third-party transportation expenses paid by Range). The following table summarizes transportation, gathering, processing and compression expense for the last two years (in thousands) and on a per mcf and per barrel basis:

	Year Ended December 31,			
	2023	2022	Change	% Change
Transportation, gathering, processing and compression				
Natural gas	$ 588,970	$ 677,316	$ (88,346)	(13%)
NGLs	524,114	565,614	(41,500)	(7%)
Oil	857	11	846	7,691%
Total	$ 1,113,941	$ 1,242,941	$ (129,000)	(10%)
Natural gas (per mcf)	$ 1.09	$ 1.26	$ (0.17)	(13%)
NGLs (per bbl)	$ 13.81	$ 15.54	$ (1.73)	(11%)
Oil (per bbl)	$ 0.35	$ —	$ 0.35	100%

Derivative fair value income (loss) was a gain of $821.2 million in 2023 compared to a loss of $1.2 billion in 2022. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. At December 31, 2023, our commodity derivative contracts were recorded at their fair value, which was a net derivative asset of $424.4 million, an increase of $563.0 million from the $138.6 million net derivative liability recorded as of December 31, 2022. We have also entered into basis swap agreements to limit volatility caused by changing differentials between NYMEX and regional prices received. These basis swaps are marked to market and we recognized a net derivative asset of $18.3 million as of December 31, 2023 compared to a net derivative asset of $521,000 as of December 31, 2022. The following table summarizes the impact of our commodity derivatives for the last two years (in thousands):

	Year Ended December 31, 2023	Year Ended December 31, 2022
Derivative fair value income (loss) per consolidated statements of income	$ 821,154	$ (1,188,506)
Non-cash fair value income (loss): (1)		
Natural gas derivatives	$ 557,419	$ (2,392)
Oil derivatives	23,301	14,783
NGLs derivatives	—	2,931
Freight derivatives	—	(114)
Contingent consideration	(13,080)	(13,560)
Total non-cash fair value income (loss) (1)	$ 567,640	$ 1,648
Net cash receipt (payment) on derivative settlements:		
Natural gas derivatives	$ 256,693	$ (1,119,940)
Oil derivatives	(11,179)	(82,546)
NGLs derivatives	—	(12,168)
Contingent consideration	8,000	24,500
Total net cash receipt (payment)	$ 253,514	$ (1,190,154)

(1) Non-cash fair value adjustments on commodity derivatives is a non-GAAP measure. Non-cash fair value adjustments on commodity derivatives only represent the net change between periods of the fair market values of commodity derivative positions and exclude the impact of settlements on commodity derivatives during the period. We believe that non-cash fair value adjustments on commodity derivatives is a useful supplemental disclosure to differentiate non-cash fair market value adjustments from settlements on commodity derivatives during the period. Non-cash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of income.

Brokered natural gas, marketing and other revenue was $218.6 million in 2023 compared to $424.2 million in 2022. We enter into purchase transactions with third parties and separate sale transactions with third parties at different times to utilize available pipeline capacity and to fulfill sales commitments in the event of operational upsets. The 2023 period includes $195.7 million of revenue from the sale of natural gas that is not related to our production (brokered) and $1.8 million of revenue from the sale of NGLs that is not related to our production, the receipt of $5.1 million in make-whole payments and $5.9 million of interest income. The 2022 period includes $408.6 million of revenue from the brokered sale of natural gas and $2.8 million of revenue from the sale of NGLs that is not related to our production and $2.5 million of interest income. These brokered revenues decreased compared to 2022 due to lower sales prices partially offset by higher brokered volumes.

Costs and Expenses per mcfe

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for the last two years:

	Year Ended December 31, 2023	2022	Change	% Change
Direct operating expense	$ 0.12	$ 0.11	$ 0.01	9%
Taxes other than income expense	0.03	0.05	(0.02)	(40%)
General and administrative expense	0.21	0.22	(0.01)	(5%)
Interest expense	0.16	0.21	(0.05)	(24%)
Depletion, depreciation and amortization expense	0.45	0.46	(0.01)	(2%)

Direct operating expense was $96.1 million in 2023 compared to $84.3 million in 2022. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workover and repair-related expenses. On an absolute dollar basis, our direct operating expenses for 2023 increased 14% from the prior year primarily due to higher water hauling/handling costs, higher labor costs and higher workover costs. We incurred $4.5 million of workover costs in 2023 compared to $3.0 million of workover costs in 2022.

On a per mcfe basis, operating expense for 2023 increased $0.01, or 9% from the same period of 2022, with the increase due to higher workover costs. Stock-based compensation expense represents the amortization of equity grants as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for the last two years:

	Year Ended December 31,			
	2023	2022	Change	% Change
Direct operating				
Lease operating expense	$ 0.11	$ 0.11	$ —	—%
Workovers	0.01	—	0.01	100%
Stock-based compensation	—	—	—	—%
Total direct operating expense	$ 0.12	$ 0.11	$ 0.01	9%

Taxes other than income expense was $23.7 million in 2023 compared to $35.4 million in 2022. This expense category is primarily the Pennsylvania impact fee. In 2012, Pennsylvania enacted an "impact fee" on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year wells are drilled and the fee varies, like a severance tax, based upon natural gas prices. The year ended December 31, 2023 includes a $21.8 million impact fee compared to $33.2 million in the year ended December 31, 2022, with the decrease primarily due to lower natural gas prices. This category also includes other taxes such as franchise, real estate and commercial activity taxes. The following table summarizes taxes other than income per mcfe for the last two years:

	Year Ended December 31,			
	2023	2022	Change	% Change
Taxes other than income				
Impact fee	$ 0.03	$ 0.04	$ (0.01)	(25%)
Other	—	0.01	(0.01)	(100%)
Total taxes other than income	$ 0.03	$ 0.05	$ (0.02)	(40%)

General and administrative expense was $164.7 million for 2023 compared to $168.1 million for 2022. The decrease in 2023, when compared to 2022, is primarily due to lower stock-based compensation and lower legal expenses partially offset by higher salaries and benefit costs. As of December 31, 2023, the number of general and administrative employees was the same when compared to December 31, 2022.

On a per mcfe basis, general and administrative expense for 2023 was 5% lower when compared to the same period of 2022 due to lower stock-based compensation. Stock-based compensation expense represents the amortization of stock-based compensation awards granted to our employees and our non-employee directors as part of their compensation. The following table summarizes general and administrative expenses per mcfe for the last two years:

	Year Ended December 31,			
	2023	2022	Change	% Change
General and administrative				
General and administrative	$ 0.16	$ 0.16	$ —	—%
Stock-based compensation	0.05	0.06	(0.01)	(17%)
Total general and administrative expense	$ 0.21	$ 0.22	$ (0.01)	(5%)

Interest expense was $124.0 million for 2023 compared to $165.1 million for 2022. The following table summarizes interest expense per mcfe for the last two years:

	Year Ended December 31,			
	2023	2022	Change	% Change
Bank credit facility	$ 0.01	$ 0.01	$ —	—%
Senior notes	0.14	0.19	(0.05)	(26%)
Amortization of deferred financing costs and other	0.01	0.01	—	—%
Total interest expense	$ 0.16	$ 0.21	$ (0.05)	(24%)
Average debt outstanding (in thousands)	$ 1,821,940	$ 2,510,107	$ (688,167)	(27%)
Average interest rate [(a)]	6.5%	6.25%	0.25%	4%

(a) Includes commitment fees but excludes amortization of debt issue costs.

On an absolute basis, the decrease in interest expense for 2023 from 2022 was primarily due to lower overall outstanding average debt balances. See Note 6 to our consolidated financial statements for additional information. Average debt outstanding on the bank credit facility for 2023 was $8.0 million compared to $48.4 million for 2022 and the weighted average interest rate on the bank credit facility was 8.4% for 2023 compared to 4.1% in 2022.

Depletion, depreciation and amortization ("DD&A") was $350.2 million in 2023 compared to $353.4 million in 2022. The decrease in 2023 when compared to 2022 is due to a 2% decrease in depletion rates. On a per mcfe basis, DD&A decreased to $0.45 in 2023 compared to $0.46 in 2022. Depletion expense, the largest component of DD&A, was $0.44 per mcfe in 2023 compared to $0.45 per mcfe in 2022. We have historically adjusted our depletion rates in the fourth quarter of each year based on our year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs. The following table summarizes DD&A expenses per mcfe for the last two years:

	Year Ended December 31,			
	2023	2022	Change	% Change
DD&A				
Depletion and amortization	$ 0.44	$ 0.45	$ (0.01)	(2%)
Accretion and other	0.01	0.01	—	—%
Total DD&A expenses	$ 0.45	$ 0.46	$ (0.01)	(2%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, brokered natural gas and marketing, exploration expense, abandonment and impairment of unproved properties, exit costs, deferred compensation plan and gain or loss on early extinguishment of debt. The following table details stock-based compensation that is allocated to functional expense categories for the last two years (in thousands):

	2023	2022
Direct operating expense	$ 1,723	$ 1,459
Brokered natural gas and marketing expense	2,095	2,439
Exploration expense	1,250	1,578
General and administrative expense	35,850	42,023
Total stock-based compensation	$ 40,918	$ 47,499

Stock-based compensation includes the amortization of restricted stock and performance-based grants.

Brokered natural gas and marketing expense was $202.9 million in 2023 compared to $427.0 million in 2022. We enter into purchase transactions with third parties and separate sale transactions with third parties at different times to utilize available pipeline capacity and fulfill sales commitments in the event of operational upsets. The decrease in these costs reflects lower purchase prices partially offset by higher purchased volumes. The following table details our brokered natural gas, marketing and other net margin which includes the net effect of these third-party transactions for the two-year period ended December 31, 2023 (in thousands):

	2023	2022
Brokered natural gas and marketing		
Brokered natural gas sales	$ 195,656	$ 408,584
Brokered NGLs sales	1,834	2,783
Interest income	5,937	2,538
Other marketing revenue and other income	15,176	10,312
Brokered natural gas purchases and transportation	(191,659)	(413,911)
Brokered NGLs purchases	(1,632)	(2,808)
Other marketing expense	(9,593)	(10,329)
Net brokered natural gas and marketing margin	$ 15,719	$ (2,831)

Exploration expense was $26.5 million in 2023 compared to $26.8 million in 2022. Exploration expense in 2023 was lower when compared to the prior year with lower delay rentals partially offset by higher seismic and personnel costs. Stock-based compensation represents the amortization of equity stock grants as part of the compensation of our exploration staff. The following table details our exploration related expenses for the last two years (in thousands):

	Year Ended December 31,			
	2023	2022	Change	% Change
Exploration				
Seismic	$ 1,687	$ 237	$ 1,450	612%
Delay rentals and other	17,644	19,576	(1,932)	(10%)
Personnel expense	5,949	5,381	568	11%
Stock-based compensation expense	1,250	1,578	(328)	(21%)
Total exploration expense	$ 26,530	$ 26,772	$ (242)	(1%)

Abandonment and impairment of unproved properties was $46.4 million in 2023 compared to $28.6 million in 2022. These costs increased when compared to the same period of 2022 due to higher estimated lease expirations in Pennsylvania. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property.

Exit costs in 2023 were $99.9 million compared to $70.3 million in 2022. In August 2020, we completed the sale of our North Louisiana operations in a transaction that included the retention of certain related gathering, transportation and processing obligations extending until 2030. The present value of these estimated future obligations totaled $479.8 million which was recorded in third quarter 2020. In the twelve months ended December 31, 2023, we recorded $41.9 million accretion expense related to these retained liabilities and in second quarter 2023, we recorded an adjustment of $37.8 million to increase this obligation for an increase in forecasted rates due to inflation. In addition, in fourth quarter 2023, we recorded an additional $18.0 million adjustment to increase the obligation for a change to our forecasted drilling plans of the buyer. In the twelve months ended December 31, 2022, we recorded $43.6 million accretion expense related to these retained liabilities and we recorded an adjustment of $24.8 million to increase this obligation for a change in forecasted drilling plans of the buyer and other adjustments. The following table details our exit costs for the last two years (in thousands):

	Year Ended December 31,	
	2023	2022
Exit costs		
Divestiture contract obligation (including accretion of discount)	$ 99,595	$ 69,758
Transportation contract capacity releases (including accretion of discount)	345	579
Total exit costs	$ 99,940	$ 70,337

Deferred compensation plan expense was $26.6 million in 2023 compared to $61.9 million in 2022. Our stock price increased to $30.44 at December 31, 2023 from $25.02 at December 31, 2022. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Common shares are placed in the deferred compensation plan when granted to eligible participants. The deferred compensation plan held 1.5 million vested shares at December 31, 2023 compared to 5.3 million shares at December 31, 2022.

Gain (loss) on early extinguishment of debt was a gain of $438,000 in 2023 compared to a loss of $69.5 million in 2022. In second quarter 2023, we purchased on the open market $61.6 million principal amount of 4.875% senior notes due 2025 at a discount and recorded a gain of $438,000, net of transaction costs and the expensing of deferred financing costs on the repurchased debt. In first quarter 2022, we announced a call for the redemption of $850.0 million of our outstanding 9.25% senior notes due 2026 which were redeemed on February 1, 2022. The redemption price equaled 106.938% of par plus accrued and unpaid interest. We recognized a loss on early extinguishment of debt of $69.2 million.

Income tax expense was $229.2 million in 2023 compared to $230.5 million in 2022. Income tax expense was the same as the prior year with lower operating income offset by the impact of changes in our valuation allowances each year.

The following is a summary of income tax expense (in thousands):

	Year Ended December 31,	
	2023	2022
Income tax expense		
Current tax expense	$ 1,547	$ 14,688
Deferred income tax expense	227,654	215,772
Total income tax expense	$ 229,201	$ 230,460
Combined federal and state effective income tax rate	20.8%	16.3%

See Note 4 to our consolidated financial statements for further detail.

Management's Discussion and Analysis of Financial Condition, Cash Flows, Capital Resources and Liquidity

Commodity prices are the most significant factor impacting our revenues, net income, operating cash flows, the amount of capital we invest in our business, payment of dividends and funding of share repurchases. Commodity prices have been and are expected to remain volatile. Our top priorities for using cash provided by operations are to fund our capital budget program, debt repayments and return capital to stockholders. We currently believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future and across a wide range of commodity price environments.

Cash Flows

The following table presents sources and uses of cash and cash equivalents for the last two years (in thousands):

	2023	2022
Sources of cash and cash equivalents		
Operating activities	$ 977,892	$ 1,864,744
Disposal of assets	872	518
Borrowing on credit facility	185,000	972,000
Issuance of new senior notes	—	500,000
Other	124,722	72,713
Total sources of cash and cash equivalents	$ 1,288,486	$ 3,409,975
Uses of cash and cash equivalents		
Additions to natural gas and oil properties	$ (571,819)	$ (456,505)
Acreage purchases	(34,410)	(30,885)
Other property	(701)	(682)
Repayments on credit facility	(204,000)	(953,000)
Repayment of senior notes	(60,934)	(1,659,422)
Purchases of treasury stock	(19,042)	(399,699)
Dividends paid	(77,241)	(38,638)
Other	(108,572)	(85,359)
Total uses of cash and cash equivalents	$ (1,076,719)	$ (3,624,190)

Sources of Cash and Cash Equivalents

Cash flow from operating activities in 2023 was $977.9 million compared to $1.9 billion in 2022. Cash provided from operating activities is largely dependent upon commodity prices and production volumes, net of the effects of settlement of our derivative contracts. The decrease in cash provided from operating activities in 2023 from 2022 reflects significantly lower realized prices partially offset by the impact of a favorable change in working capital outflow (the timing of cash receipts and disbursements). As of December 31, 2023, we have hedged more than 45% of our projected total production for 2024 with more than 50% of our projected natural gas production hedged. Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2023 was an outflow of $121.1 million compared to an outflow of $169.3 million for 2022.

Uses of Cash and Cash Equivalents

Additions to natural gas and oil properties are our most significant use of cash and cash equivalents. These cash outlays are associated with our drilling and completion capital budget program. The following table shows capital expenditures and reconciles to additions to natural gas and oil properties as presented on our consolidated statements of cash flows for the last two years (in thousands):

	2023	2022
Appalachia	$ 571,607	$ 462,134
Change in capital expenditure accrual for proved properties	1,204	(4,116)
Change in other non-cash capital expenditures	(992)	(1,513)
Additions to natural gas and oil properties	$ 571,819	$ 456,505

Repayment of senior notes for 2023 includes the repurchase of $61.6 million principal of our 4.875% senior notes due 2025, at a discount.

Purchases of treasury stock for 2023 include the repurchase of 715,000 shares of common stock for a total of $19.0 million as part of our previously announced stock repurchase program.

Liquidity and Capital Resources

Our main sources of liquidity are cash, internally generated cash flow from operations, capital market transactions and our bank credit facility. At December 31, 2023, we had approximately $1.5 billion of liquidity consisting of cash on hand and availability under our bank credit facility.

Our liquidity requirements are supported by our cash on hand and our bank credit facility. We may draw on our bank credit facility to meet short-term cash requirements or issue debt or equity securities through the shelf registration discussed below as part of our longer-term liquidity and capital management. We believe our short-term and long-term liquidity is adequate to fund our current operations and our near-term and long-term funding requirements including our capital spending programs, repayment of debt maturities and dividends. Although we expect cash flows to be sufficient to fund our expected 2024 capital program, we may elect to use the bank credit facility or raise funds through new debt or equity offerings or from other sources of financing.

Bank Credit Facility

Our bank credit facility is secured by substantially all of our assets. In April 2022, we entered into an amended bank credit facility with a maturity date of April 14, 2027. As of December 31, 2023, we had no outstanding borrowings under our bank credit facility and we maintain a borrowing base of $3.0 billion and aggregate lender commitments of $1.5 billion. We also have undrawn letters of credit of $173.4 million as of December 31, 2023 which reduce the borrowing capacity under our bank credit facility.

The borrowing base is subject to regular, semi-annual redeterminations and is dependent on a number of factors but primarily the lender's assessment of future cash flows. The next scheduled borrowing base redetermination is during the spring of 2024. We currently must comply with certain financial and non-financial covenants, including limiting dividend payments, debt incurrence and requirements that we maintain certain financial ratios (as defined in our bank credit agreement). We were in compliance with all such covenants at December 31, 2023. See Note 6 to our consolidated financial statements for more information.

Capital Requirements

Our material cash requirements include the following contractual and other potential or expected obligations:

Capital Budget

Our approved capital budget for 2024 is $620 million to $670 million. The amount of our future capital expenditures will depend upon a number of factors including our cash flows from operations, investing and financing activities, infrastructure availability, supply and demand fundamentals and our ability to execute our development program. We periodically review our budget to assess changes in current and projected cash flows, debt requirements and other factors.

Long-Term Debt

As of December 31, 2023, we had $1.8 billion of total long-term debt outstanding. Our next significant long-term debt maturity is in the amount of $688.4 million due 2025. Anticipated cash annual interest payments related to our fixed-rate debt, based on the amount outstanding at December 31, 2023, is $23.8 million on our 4.75% senior notes, $33.6 million on our 4.875% senior notes and $49.5 million on our 8.25% senior notes.

Stock Repurchase Program

Our total remaining share repurchase authorization was approximately $1.1 billion at December 31, 2023.

Other Sources of Liquidity

We have a universal shelf registration statement filed with the SEC under which we, as a "well-known seasoned issuer" for purposes of SEC rules, have the ability to sell an indeterminate amount of various types of debt and equity securities.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations and transportation, gathering and processing commitments. As of December 31, 2023, we do not have any capital leases or any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of December 31, 2023, we had a total of $173.4 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2023. In addition to the contractual obligations listed in the table below, our consolidated balance sheet at December 31, 2023 reflects accrued interest payable on our bank debt of $41,000, which is payable in first quarter 2024.

The following summarizes our contractual financial obligations at December 31, 2023 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, and, if necessary, borrowings under our bank credit facility or other sources (in thousands):

	Payment due by period					
	2024	2025	2026	2027 and 2028	Thereafter	Total
Debt:						
Bank debt due 2027 [(a)]	$ —	$ —	$ —	$ —	$ —	$ —
4.875% senior notes due 2025	—	688,388	—	—	—	688,388
8.25% senior notes due 2029	—	—	—	—	600,000	600,000
4.75% senior notes due 2030	—	—	—	—	500,000	500,000
Other obligations:						—
Operating leases	13,119	7,921	6,866	2,698	29	30,633
Software licenses and other	2,117	576	279	16	—	2,988
Derivative obligations [(b)]	222	107	—	—	—	329
Transportation and gathering commitments [(c)]	801,694	730,907	670,692	616,260	3,070,613	5,890,166
Asset retirement obligation liability [(d)]	2,395	38	—	—	114,996	117,429
Total contractual obligations [(e)]	$ 819,547	$1,427,937	$ 677,837	$ 618,974	$ 4,285,638	$ 7,829,933

(a) We had no outstanding balance as of the end of the year.

(b) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity derivatives that were valued as of December 31, 2023. Our derivatives are measured and recorded at fair value and are subject to market and credit risk. The ultimate liquidation value will be dependent upon actual future commodity prices which may differ materially from the inputs used to determine fair value as of December 31, 2023. See Note 8 to our consolidated financial statements.

(c) The obligations above represent our minimum financial commitments pursuant to the terms of these contracts. Our actual expenditures may exceed these minimum commitments.

(d) The amount above represents the discounted values. There are inherent uncertainties surrounding the obligations and the actual amount and timing may differ from our estimates. See Note 7 to our consolidated financial statements.

(e) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets and does not include obligations to taxing authorities.

We have also entered into an additional agreement which modifies existing contracts that are included in the cash contractual obligation table above but is contingent on additional facility construction and is expected to begin in 2024 with a twelve-year term and adds to our ability to efficiently flow production volumes. The revised agreement covers volumes of 650,000 mcf per day but declines in the last five years of the contract ending at 300,000 mcf per day.

Not included in the table above is our estimate of accrued contractual obligations related to certain obligations retained by us after our divestiture of our North Louisiana assets in 2020. These contractual obligations are related to gathering, processing and transportation agreements including certain minimum volume commitments. There are inherent uncertainties surrounding the retained obligation and, as a result, the determination of the accrued obligation required significant judgment and estimation. The actual settlement amount and timing may differ from our estimates. See also Note 13 and Note 14 to our consolidated financial statements. As of December 31, 2023, the carrying value of this obligation was $397.4 million (discounted) and is included in divestiture contract obligation in our consolidated balance sheets. As of December 31, 2023, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

	Year Ended December 31,
2024	$ 86,762
2025	77,418
2026	61,805
2027	52,622
2028	48,116
Thereafter	70,727
	$ 397,450

Income Taxes

We are subject to income and non-income-based taxes under federal, state and local jurisdictions in which we operate. Historically, we have generated and carried forward net operating losses ("NOL") in amounts sufficient to offset all our taxable income at the federal level. To the extent we utilize all or substantially all of our federal NOL carryovers, we expect to begin to make federal income tax payments. In addition, the Inflation Reduction Act of 2022 could trigger minimum income taxes if we become subject to the corporate alternative minimum tax where we may have to make estimated federal income tax payments. We currently pay state income taxes in the Commonwealth of Pennsylvania. See Note 4 to our consolidated financial statements for more information.

Proved Reserves

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Year End December 31,	
	2023	2022
	(Mmcfe)	
Proved Reserves:		
Beginning of year	18,077,656	17,775,484
Reserve revisions	608,784	(591,983)
Reserve extensions, discoveries and additions	207,260	1,668,244
Production	(780,575)	(774,089)
End of year	18,113,125	18,077,656
Proved Developed Reserves:		
Beginning of year	10,933,180	10,417,887
End of year	11,535,852	10,933,180

Our proved reserves at year-end 2023 were 18.1 Tcfe which were slightly higher than year-end 2022. Natural gas comprised approximately 64% of our proved reserves at year-end 2023.

Reserve Revisions and Additions. Revisions of previous estimates of a positive 608.8 Bcfe includes a positive revision of 280.2 Bcfe for previously undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan and positive performance revisions of 701.4 Bcfe due to improved well performance and longer lateral lengths partially offset by negative pricing revisions and 370.6 Bcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. We added 207.3 Bcfe of proved reserves from drilling activities and evaluation of proved areas in

Pennsylvania. Our ethane reserves are intended to match volumes delivered under our existing long-term, extendable contracts along with meeting pipeline specifications.

During 2022, we added 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas in Pennsylvania. Approximately 77% of the 2022 reserve additions are attributable to natural gas. Our ethane reserves are intended to match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of a negative 592.0 Bcfe includes 1.4 Tcfe reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five year development horizon significantly offset by favorable pricing revisions, positive performance revisions of 72.8 Bcfe and 716.2 Bcfe for previously proved undeveloped properties as they were added back to our five-year development plan. Wells reclassified to unproved during the year are the result of the out-performance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations.

Future Net Cash Flows. At December 31, 2023, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $7.9 billion. The present value of our estimated future net cash flows at December 31, 2022 was $29.6 billion. This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves, in accordance with SEC rules. At December 31, 2023, the after-tax present value of estimated future net cash flows from our proved reserves was $6.8 billion compared to $24.5 billion at December 31, 2022.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale properties. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third-party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2023, our delivery commitments through 2037 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2024	302,404	70,000
2025	282,493	54,932
2026	200,548	50,000
2027	100,000	46,233
2028	100,000	45,000
2029	100,000	33,444
2030	-	30,000
2031	-	16,575
2032 - 2037	-	10,000 (each year)

Other

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages, or other events could result in significant future costs. We also regularly provide letters of credit in the normal course of business under certain contracts that may be drawn if we fail to perform under those contracts.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resources position. However, as is customary in the natural gas and oil industry, we have various contractual work commitments which are described above under cash contractual obligations.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. One difference between the successful efforts method of accounting and the full cost method is that under the successful efforts method, all exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur; whereas, under the full cost method of accounting, such costs are capitalized as assets, pooled with the costs of successful wells and charged against earnings of future periods as a component of depletion expense. Under the successful efforts method of accounting, successful exploration drilling costs and all development costs are capitalized and these costs are systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves for which a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start up or shut in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to audit our estimates of proved reserves. Estimates prepared by third parties may be higher or lower than those included herein. Independent petroleum consultants audited approximately 96% of our reserves in both 2023 and 2022. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been approximately 5%. The reserves included in this report are those reserves estimated by our petroleum engineering staff. For additional discussion, see Items 1 & 2. Business and Properties – *Proved Reserves*.

Reserves are based on the weighted average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC. When determining the December 31, 2023 proved reserves for each property, benchmark prices are adjusted using price differentials that account for property-specific quality and location differences. If prices in the future average below prices used to determine reserves at December 31, 2023, it could have an adverse effect on our estimates of proved reserves. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves due to numerous factors (including commodity prices and performance revisions).

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2023, we estimate that a 1% change in proved reserves would increase or decrease 2024 depletion expense by approximately $3.0 million (based on current production estimates). We currently expect our DD&A rate to be approximately $0.44 per mcfe in 2024. Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 15 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. It should not be assumed that the standardized measure is the current market value of our estimated proved reserves.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1-Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2-Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3-Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Note 9 to the consolidated financial statements for disclosures regarding our fair value measurements.

The need to test long-lived assets for impairment can be based on several indicators, including reductions in commodity prices, reductions to our capital budget, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which a property is located. Valuation methods used to measure fair value may require significant management judgement and estimates to derive the inputs necessary to determine fair value.

Whenever changes in facts and circumstances indicate that the carrying value of our long-lived assets may not be recoverable, we perform an impairment evaluation. For purposes of this evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. As of December 31, 2023, our estimated undiscounted cash flows relating to our long-lived assets significantly exceeded their carrying values.

Fair value calculated for the purpose of testing our natural gas and oil properties for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. An estimate of the sensitivity to changes in assumptions in our undiscounted cash flow calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, operating costs, drilling and development costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future undiscounted cash flows would likely be partially offset by lower costs.

We record all derivative instruments at fair value. Fair value measurements are based on observable market-based inputs that are corroborated by market data and are discussed more fully in Note 8 to our consolidated financial statements and in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Exit Cost Estimates

Our consolidated balance sheets include accrued exit cost obligations related to retained gathering, processing and transportation contracts associated with divestiture of our North Louisiana assets during 2020. Inherent in the initial fair value calculation of these exit costs were numerous assumptions and judgments including the ultimate amounts to be paid, the credit-adjusted discount rates, the development plans of the buyer and our probability weighted forecast of those drilling plans, market conditions and the ultimate usage by the buyer of each facility included in the agreement. A significant portion of this obligation is a gas processing agreement that includes a deficiency payment if the minimum volume commitment is not met and we must assess the likelihood and amount of production volumes flowing to this facility. In addition, our agreement includes additional transportation agreements that are based on contractual rates applied to a minimum volume usage. We have made significant judgments and estimates regarding the timing and amount of these liabilities. We based our initial fair value estimate on assumptions we believed to be reasonable and likely to occur. We have continued to refine our forecast of the buyer's development plans since the divestiture. Changes in other assumptions, such as the estimate of production volumes flowing to certain processing facilities, could result in a higher liability. If we assume the flow of production volumes was held flat through the end of the contract, the liability could increase by approximately $9.1 million. If the forecasted inflation rates were to increase or decrease in the amount of 1%, the difference in the liability would be $9.4 million. We continue to regularly monitor our estimates and in the future may be required to adjust our estimates based on facts and circumstances. See Note 13 and Note 14 to our consolidated financial statements for a further discussion of these costs.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws. Our effective tax rate is subject to variability as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which could affect us. Our effective rate is also affected by changes in the allocation of revenue among states.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the potential realization of deferred tax assets, management must consider whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income, new legislation and tax planning strategies in making this assessment and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine that an additional deferred tax asset valuation allowance should be established. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production, development activities, profitability of future business strategies and forecasted economics in the oil and gas industry. Additionally, changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and will affect valuation of deferred tax balances in the future. Changes in judgment regarding future realization of deferred tax assets may result in a reversal of all or a portion of the valuation allowance. See Note 4 to our consolidated financial statements for additional information.

An estimate of the sensitivity to changes in our assumptions resulting in future income calculations is not practical, given the numerous assumptions that can materially affect our estimates. Unfavorable adjustments to some of the assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future taxable income would likely be partially offset by lower capital expenditures.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, income or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Accounting Standards Not Yet Adopted

None that are expected to have a material impact.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future. We employ various strategies, including diverse sales locations and the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price changes related to the underlying commodity transaction. While the use of derivative instruments could materially affect our results of operations in a particular quarter or annual period, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas prices affect us more than oil prices because approximately 64% of our December 31, 2023 proved reserves were natural gas compared to 2% of proved reserves were oil. In addition, a portion of our NGLs, which are 34% of proved reserves, are also impacted by changes in oil prices. At times, we are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2022 to December 31, 2023.

We believe NGLs prices are somewhat seasonal, particularly for propane. Therefore, the relationship of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional and international markets. If we are not able to sell or store NGLs, we may be required to curtail production or shift our drilling activities to dry gas areas.

The Appalachian region has limited local demand and infrastructure to accommodate ethane. We have agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area. We cannot ensure that these facilities will remain available. If we are not able to sell ethane under at least one of our agreements, we may be required to curtail production or, as we have done in the past, purchase or divert natural gas to blend with our rich residue gas.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program may also include collars, which establish a minimum floor price and a predetermined ceiling price. Our program may also include a three-way collar which is a combination of three options: a sold call, a purchased put and a sold put. The sold call establishes the ceiling price while the purchased put establishes the floor price until the market price for the commodity falls below the sold put stock price at which price the value of the purchased put is effectively capped. We have also entered into natural gas derivative instruments containing a fixed price swap and a sold option (which we refer to as a swaption). At December 31, 2023, our derivatives program includes swaps, collars, three-way-collars and swaptions. These contracts expire monthly through December 2026. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2023, approximated a net derivative asset of $424.4 million compared to a net derivative liability of $138.6 million at December 31, 2022. This change is primarily related to changes in futures prices for natural gas and oil, the settlements of derivative contracts during 2023 and the new commodity derivative contracts we entered into during 2023 for 2024, 2025 and 2026. At December 31, 2023, the following commodity derivative contracts were outstanding, excluding our basis swaps which is separately discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price				Fair Market Value (in thousands)
			Swap	Sold Put	Floor	Ceiling	
Natural Gas [(a)]							
2024	Swaps	304,973 Mmbtu/day	$ 4.01				$ 146,481
2024	Collars	436,694 Mmbtu/day			$ 3.50	$ 5.63	$ 150,456
2024	Three-way Collars	93,511 Mmbtu/day		$ 2.50	$ 3.40	$ 4.15	$ 20,935
2025	Swaps	400,000 Mmbtu/day	$ 4.12				$ 85,495
2025	Three-way Collars	30,000 Mmbtu/day		$ 2.70	$ 4.00	$ 5.00	$ 4,471
2026	Swaps	60,000 Mmbtu/day	$ 4.15				$ 6,489
Crude Oil							
January-September 2024	Swaps	4,000 bbls/day	$ 80.25				$ 9,115
January-September 2024	Collars	832 bbls/day			$ 80.00	$ 90.12	$ 2,084

(a) We sold natural gas swaptions of 40,000 Mmbtu/day for calendar year 2026 at a weighted average price of $4.11/Mmbtu that expire June 2024. The fair value of these swaptions at December 31, 2023 was a net derivative liability of $1.2 million.

Other Commodity Risk

We are impacted by basis risk as natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the derivative contracts above, we have entered into natural gas basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively lock in the basis adjustments. The fair value of the natural gas basis swaps, which expire monthly through December 2026, was a net derivative asset of $18.3 million at December 31, 2023 and the volumes are for 313,453,000 Mmbtu.

Commodity Sensitivity Analysis

The following table shows the fair value of our derivative contracts and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2023. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change In Fair Value			
		Increase in Commodity Price of		Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Swaps	$ 247,580	$ (91,637)	$ (229,092)	$ 91,637	$ 229,091
Collars	152,540	(32,701)	(75,366)	35,426	92,944
Three-way collars	25,406	(7,245)	(18,954)	5,817	11,781
Swaptions	(1,161)	(2,419)	(8,887)	935	1,156
Basis swaps	18,277	21,317	53,293	(21,317)	(53,292)

Counterparty Risk

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and commodity traders and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2023, our derivative counterparties include fourteen financial institutions, of which all but six are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions and large commodity traders, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial.

Interest Rate Risk

At December 31, 2023, we had total debt of $1.8 billion. All of our outstanding debt is based on fixed interest rates and, as a result, we do not have significant exposure to movements in market interest rates at this time. Our credit facility provides for variable interest rate borrowings; however, we did not have any borrowings outstanding as of December 31, 2023. See Note 6 to our consolidated financial statements for more information about our senior notes.

The fair value of our senior debt is based on December 31, 2023 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Notes due 2025	$ 688,388	$ 679,363
(The interest rate is fixed at a rate of 4.875%)		
Senior Notes due 2029	600,000	624,816
(The interest rate is fixed at a rate of 8.25%)		
Senior Notes due 2030	500,000	463,085
(The interest rate is fixed at a rate of 4.75%)		
	$ 1,788,388	$ 1,767,264

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders of Range Resources Corporation:

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting (as defined in Rule 13(a)-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and presentation of consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide 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 the internal controls may become inadequate because of changes in conditions or because the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2023. In making this assessment, which was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013).* Based on our assessment, we believe that, as of December 31, 2023, our internal control over financial reporting was effective based on those criteria.

Ernst and Young LLP, our independent registered public accounting firm, audited our financial statements included in this annual report and has issued an attestation report on our internal control over financial reporting as of December 31, 2023. Their report appears on the following page.

By: /s/ DENNIS L. DEGNER
Dennis L. Degner
Chief Executive Officer and President

By: /s/ MARK S. SCUCCHI
Mark S. Scucchi
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
February 21, 2024

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Range Resources Corporation'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) (the COSO criteria). In our opinion, Range Resources Corporation (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, and the related consolidated statements of income, comprehensive income (loss), 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 21, 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

Fort Worth, Texas
February 21, 2024

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income (loss), 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 21, 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 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 of proved natural gas and oil properties

Description of the Matter	At December 31, 2023, the net book value of the Company's proved natural gas and oil properties totaled $5.3 billion and depletion, depreciation and amortization expense ("DD&A") was $350.2 million for the year then ended. As described in Note 2 to the consolidated financial statements, the Company follows the successful efforts method of accounting for its natural gas and oil producing activities. Under this method, DD&A for proved properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided using the units of production method based on proved natural gas and oil reserves, as estimated by the Company's petroleum engineering staff. Proved oil and gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Judgment is required by the Company's petroleum engineering staff in interpreting the data used to estimate reserves. Estimating proved natural gas and oil reserves requires the selection and evaluation of inputs, including historical production, natural gas and oil price assumptions, and future operating and capital cost assumptions, among others. Because of the complexity involved in estimating natural gas and oil reserves, management used independent petroleum consultants to audit the proved reserve estimates prepared by the Company's petroleum engineering staff as of December 31, 2023.

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

We obtained an understanding, evaluated the design and tested the operating effectiveness of the internal controls that address the risks of material misstatement relating to the DD&A calculation, including controls over the completeness and accuracy of the financial data used in estimating proved natural gas and oil reserves.

How We Addressed the Matter in Our Audit

Our testing of the Company's DD&A calculation included, among other procedures evaluating the professional qualifications and objectivity of the individual primarily responsible for overseeing the preparation of the reserve estimates by the petroleum engineering staff and the independent petroleum consultants used to audit the estimates. On a sample basis, we tested the completeness and accuracy of the financial data used in the estimation of proved natural gas and oil reserves by agreeing significant inputs to source documentation, where applicable, and assessing the inputs for reasonableness based on our review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic procedures on select inputs into the natural gas and oil reserve estimate as well as look back procedures on the output. Finally, we tested that the DD&A calculation is based on the appropriate proved natural gas and oil reserve amounts from the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2003.

Fort Worth, Texas
February 21, 2024

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2023	December 31, 2022
Assets		
Current assets:		
Cash and cash equivalents	$ 211,974	$ 207
Accounts receivable, less allowance for doubtful accounts of $308 and $314	274,669	481,050
Contingent consideration receivable	8,000	24,500
Derivative assets	341,330	925
Prepaid assets	18,159	20,795
Other current assets	15,992	12,110
Total current assets	870,124	539,587
Derivative assets	101,641	40,990
Natural gas and oil properties, successful efforts method	11,225,482	10,655,879
Accumulated depletion and depreciation	(5,107,801)	(4,765,475)
	6,117,681	5,890,404
Other property and equipment	72,639	74,638
Accumulated depreciation and amortization	(70,943)	(72,204)
	1,696	2,434
Operating lease right-of-use assets	23,821	84,070
Other assets	88,922	68,077
Total assets	$ 7,203,885	$ 6,625,562
Liabilities		
Current liabilities:		
Accounts payable	$ 110,134	$ 206,738
Asset retirement obligations	2,395	4,570
Accrued liabilities	302,163	442,922
Deferred compensation liabilities	44,149	89,334
Accrued interest	37,261	39,138
Derivative liabilities	222	151,417
Divestiture contract obligation	86,762	86,546
Total current liabilities	583,086	1,020,665
Bank debt	—	9,509
Senior notes	1,774,229	1,832,451
Deferred tax liabilities	561,288	333,571
Derivative liabilities	107	15,495
Deferred compensation liabilities	72,976	99,907
Operating lease liabilities	16,064	20,903
Asset retirement obligations and other liabilities	119,896	112,981
Divestiture contract obligation	310,688	304,074
Total liabilities	3,438,334	3,749,556
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par 475,000,000 shares authorized, 265,756,369 issued at December 31, 2023 and 262,887,265 issued at December 31, 2022	2,658	2,629
Common stock held in treasury, at cost, 24,716,065 shares at December 31, 2023 and 24,001,535 shares at December 31, 2022	(448,681)	(429,659)
Additional paid-in capital	5,879,705	5,764,970
Accumulated other comprehensive gain	647	467
Retained deficit	(1,668,778)	(2,462,401)
Total stockholders' equity	3,765,551	2,876,006
Total liabilities and stockholders' equity	$ 7,203,885	$ 6,625,562

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31,		
	2023	2022	2021
Revenues and other income:			
Natural gas, NGLs and oil sales	$ 2,334,661	$ 4,911,092	$ 3,215,027
Derivative fair value income (loss)	821,154	(1,188,506)	(650,216)
Brokered natural gas, marketing and other	218,603	424,217	365,412
Total revenues and other income	3,374,418	4,146,803	2,930,223
Costs and expenses:			
Direct operating	96,085	84,286	75,287
Transportation, gathering, processing and compression	1,113,941	1,242,941	1,174,469
Taxes other than income	23,726	35,367	30,648
Brokered natural gas and marketing	202,884	427,048	367,288
Exploration	26,530	26,772	23,555
Abandonment and impairment of unproved properties	46,359	28,608	7,206
General and administrative	164,740	168,085	168,435
Exit costs	99,940	70,337	21,661
Deferred compensation plan	26,593	61,880	68,351
Interest	124,004	165,145	227,336
(Gain) loss on early extinguishment of debt	(438)	69,493	98
Depletion, depreciation and amortization	350,165	353,420	364,555
Gain on the sale of assets	(454)	(409)	(701)
Total costs and expenses	2,274,075	2,732,973	2,528,188
Income before income taxes	1,100,343	1,413,830	402,035
Income tax expense (benefit):			
Current	1,547	14,688	7,984
Deferred	227,654	215,772	(17,727)
	229,201	230,460	(9,743)
Net income	$ 871,142	$ 1,183,370	$ 411,778
Net income per common share:			
Basic	$ 3.61	$ 4.79	$ 1.65
Diluted	$ 3.57	$ 4.69	$ 1.61
Weighted average common shares outstanding:			
Basic	236,986	240,858	242,862
Diluted	239,837	246,379	249,314

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2023	**2022**	**2021**
Net income	$ 871,142	$ 1,183,370	$ 411,778
Other comprehensive loss:			
Postretirement benefits:			
Actuarial (loss) gain	(12)	482	62
Prior service cost	296	—	—
Amortization of prior service costs	(41)	292	369
Income tax expense	(63)	(157)	(102)
Total comprehensive income	$ 871,322	$ 1,183,987	$ 412,107

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2023	**2022**	**2021**
Operating activities:			
Net income	$ 871,142	$ 1,183,370	$ 411,778
Adjustments to reconcile net income to net cash provided from operating activities:			
Deferred income tax expense (benefit)	227,654	215,772	(17,727)
Depletion, depreciation and amortization and impairment of proved properties	350,165	353,420	364,555
Abandonment and impairment of unproved properties	46,359	28,608	7,206
Derivative fair value (income) loss	(821,154)	1,188,506	650,216
Cash settlements on derivative financial instruments	253,514	(1,190,154)	(520,013)
Divestiture contract obligation	99,595	69,766	20,340
Allowance for bad debt	—	(250)	200
Amortization of deferred financing costs and other	4,735	7,959	8,347
Deferred and stock-based compensation	67,849	107,959	110,356
Gain on the sale of assets	(454)	(409)	(701)
(Gain) loss on early extinguishment of debt	(438)	69,493	98
Changes in working capital:			
Accounts receivable	223,081	(3,286)	(250,538)
Prepaid and other	(1,285)	(18,438)	(1,140)
Accounts payable	(77,057)	17,077	39,231
Accrued liabilities and other	(265,814)	(164,649)	(29,260)
Net cash provided from operating activities	977,892	1,864,744	792,948
Investing activities:			
Additions to natural gas and oil properties	(571,819)	(456,505)	(393,478)
Additions to field service assets	(701)	(682)	(1,231)
Acreage purchases	(34,410)	(30,885)	(23,962)
Proceeds from disposal of assets	872	518	303
Purchases of marketable securities held by the deferred compensation plan	(45,168)	(43,691)	(30,806)
Proceeds from the sales of marketable securities held by the deferred compensation plan	49,521	41,413	31,295
Net cash used in investing activities	(601,705)	(489,832)	(417,879)
Financing activities:			
Borrowings on credit facilities	185,000	972,000	1,434,000
Repayments on credit facilities	(204,000)	(953,000)	(2,136,000)
Issuance of senior notes	—	500,000	600,000
Repayment of senior or senior subordinated notes	(60,934)	(1,659,422)	(63,324)
Dividends paid	(77,241)	(38,638)	—
Treasury stock purchases	(19,042)	(399,699)	—
Debt issuance costs	—	(16,176)	(8,854)
Taxes paid for shares withheld	(39,481)	(25,492)	(9,299)
Change in cash overdrafts	(23,923)	9,071	16,493
Proceeds from the sales of common stock held by the deferred compensation plan	75,201	22,229	5,879
Net cash used in financing activities	(164,420)	(1,589,127)	(161,105)
Increase (decrease) in cash and cash equivalents	211,767	(214,215)	213,964
Cash and cash equivalents at beginning of year	207	214,422	458
Cash and cash equivalents at end of year	$ 211,974	$ 207	$ 214,422

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except per share data)

	Common stock Shares	Common stock Par value	Treasury shares	Common stock held in treasury	Additional paid-in capital	Accumulated other comprehensive income (loss)	Retained deficit	Total
Balance as of December 31, 2020	256,354	$ 2,563	10,006	$ (30,132)	$ 5,684,268	$ (479)	$ (4,018,685)	**$ 1,637,535**
Issuance of common stock	3,429	35	—	—	6,998	—	—	**7,033**
Issuance of common stock upon vesting of PSUs	13	—	—	—	148	—	(148)	—
Stock-based compensation expense	—	—	—	—	28,988	—	—	28,988
Treasury stock issuance	—	—	(3)	125	(125)	—	—	—
Other comprehensive income	—	—	—	—	—	329	—	329
Net income	—	—	—	—	—	—	411,778	411,778
Balance as of December 31, 2021	259,796	2,598	10,003	(30,007)	5,720,277	(150)	(3,607,055)	2,085,663
Issuance of common stock	3,089	31	—	—	13,529	—	—	13,560
Issuance of common stock upon vesting of PSUs	2	—	—	—	78	—	(78)	—
Stock-based compensation expense	—	—	—	—	31,133	—	—	31,133
Cash dividends paid ($0.16 per share)	—	—	—	—	—	—	(38,638)	(38,638)
Treasury stock issuance	—	—	(1)	47	(47)	—	—	—
Treasury stock repurchased	—	—	14,000	(399,699)	—	—	—	(399,699)
Other comprehensive income	—	—	—	—	—	617	—	617
Net income	—	—	—	—	—	—	1,183,370	1,183,370
Balance as of December 31, 2022	**262,887**	**2,629**	**24,002**	**(429,659)**	**5,764,970**	**467**	**(2,462,401)**	2,876,006
Issuance of common stock	2,863	29	—	—	78,050	—	—	78,079
Issuance of common stock upon vesting of PSUs	6	—	—	—	278	—	(278)	—
Stock-based compensation expense	—	—	—	—	36,427	—	—	36,427
Cash dividends paid ($0.32 per share)	—	—	—	—	—	—	(77,241)	(77,241)
Treasury stock issuance	—	—	(1)	20	(20)	—	—	—
Treasury stock repurchased	—	—	715	(19,042)	—	—	—	(19,042)
Other comprehensive income	—	—	—	—	—	180	—	180
Net income	—	—	—	—	—	—	871,142	871,142
Balance as of December 31, 2023	**265,756**	**$ 2,658**	**24,716**	**$ (448,681)**	**$ 5,879,705**	**$ 647**	**$ (1,668,778)**	$ 3,765,551

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

(1) Summary of Organization and Nature of Business

Range Resources Corporation ("Range," "we," "us," or "our") is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs"), crude oil and condensate company engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian region of the United States. Our objective is to build stockholder value through returns-focused development of natural gas properties. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol "RRC".

(2) Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements, including the notes, have been prepared in accordance with generally accepted accounting principles ("U.S. GAAP") and include the accounts of all of our subsidiaries. All material intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods.

Estimated quantities of natural gas, NGLs, crude oil and condensate reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas, NGLs, crude oil and condensate. There are numerous uncertainties inherent in estimating quantities of proved natural gas, NGLs, crude oil and condensate reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of natural gas, NGLs and crude oil and condensate that are ultimately recovered. See Note 15 for further detail.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, valuation of certain derivative instruments, exit cost liabilities and valuation allowances for deferred income tax assets, among others. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Business Segment Information

We have evaluated how we are organized and managed and have identified only one operating segment. We consider our gathering, processing and marketing functions as integral to our natural gas, crude oil and condensate producing activities. We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We measure financial performance as a single enterprise and not on an area-by-area basis. All of our operating revenues, income from operations and assets are generated and located in the United States.

Revenue Recognition and Accounts Receivable

Natural gas, NGLs and oil sales revenues are recognized when control of the product is transferred to the customer and collectability is reasonably assured. See below for a more detailed summary of our product types.

Natural Gas and NGLs Sales. Under some of our gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity’s system. The midstream processing entity processes the natural gas and remits proceeds to us for the resulting sales of NGLs and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For those contracts that we have concluded that we are the principal, the ultimate third party is our customer and we recognize revenue on a gross basis, with gathering, compression, processing and transportation fees presented as an expense. Alternatively, for those contracts that we have concluded that we are the agent, the midstream processing entity is our customer and we recognize revenue based on the net amount of the proceeds received from the midstream processing entity.

In other natural gas processing agreements, we may elect to take our residue gas and/or NGLs in kind at the tailgate of the midstream entity’s processing plant and subsequently market the product on our own. Through the marketing process, we deliver product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receive a specified index price from the purchaser. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression expense.

Oil Sales. Our oil sales contracts are generally structured in one of the following ways:

- We sell oil production at the wellhead and collect an agreed-upon index price, net of transportation incurred by the purchaser (that is, a netback arrangement). In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.
- We deliver oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. Under this arrangement, we pay a third party to transport the product and receive a specified index price from the purchaser with no deduction. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. The third-party costs are recorded as transportation, gathering, processing and compression expense.

Brokered Natural Gas, Marketing and Other. We realize brokered margins as a result of buying natural gas or NGLs utilizing separate purchase transactions, generally with separate counterparties, and subsequently selling that natural gas or NGLs under our existing contracts to fill our contract commitments or use existing infrastructure contracts to economically utilize available capacity. In these arrangements, we take control of the natural gas purchased prior to delivery of that gas under our existing gas contracts with a separate counterparty. Revenues and expenses related to brokering natural gas are reported gross as part of revenues and expenses in accordance with applicable accounting standards. Proceeds generated from the sale of excess firm transportation to third parties is also included here when we are determined to no longer be the primary obligor of such arrangement. Our net brokered margin was income of $4.2 million in 2023 compared to a loss of $5.4 million in 2022 and income of $1.1 million in 2021. Interest income included here was $5.9 million in 2023 compared to $2.5 million in 2022 and $243,000 in 2021.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers. We may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales or in limited cases may use them for contracts we intend to physically settle but that do not meet all of the criteria to be treated as normal sales.

Accounts Receivable. Our accounts receivable consist mainly of receivables from oil and gas purchasers and joint interest owners on properties we operate. Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. However, this concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. Each reporting period, we assess the recoverability of material receivables using historical data and current market conditions. The loss given default method is used when, based on management's judgment, an allowance for expected credit losses is accrued on material receivables to reflect the net amount to be collected. In certain instances, we require purchasers to post stand-by letters of credit. For receivables from joint interest owners, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We regularly review collectability and establish or adjust our allowance as necessary. We have allowances for doubtful accounts relating to exploration and production receivables of $308,000 at December 31, 2023 compared to $314,000 at December 31, 2022. We recorded no bad debt expense in the year ended December 31, 2023 compared to a reduction of $250,000 in the year ended December 31, 2022 and expense of $200,000 in the year ended December 31, 2021.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. Outstanding checks in excess of funds on deposit are included in accounts payable on the consolidated balance sheets and the change in such overdrafts is classified as a financing activity on the consolidated statements of cash flows.

Natural Gas and Oil Properties

Property Acquisition Costs. We use the successful efforts method of accounting for natural gas and oil producing activities. Costs to acquire mineral interests in natural gas and oil properties, to drill exploratory wells that find proved reserves and to drill development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of proved properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs.

Impairments. Our proved natural gas and oil properties are reviewed for impairment of value whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying value of the asset, an impairment loss is recognized based on the fair value of the asset. These assets are reviewed for potential impairment at the lowest level for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. Natural gas and oil properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management which could impact the number of locations we intend to drill. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Information such as reservoir performance or future plans to develop acreage is also considered. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $789.9 million as of December 31, 2023 compared to $800.6 million in 2022. We have recorded abandonment and impairment expense related to unproved properties of $46.4 million in the year ended December 31, 2023 compared to $28.6 million in 2022 and $7.2 million in 2021.

Dispositions. Proceeds from the disposal of natural gas and oil producing properties that are part of an amortization base are credited to the net book value of the amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Dispositions are accounted for as a sale of assets.

Other Property and Equipment

Other property and equipment includes assets such as buildings, furniture and fixtures, field equipment, leasehold improvements and data processing and communication equipment. These items are generally depreciated by individual components on a straight-line basis over their economic useful life, which is generally from three to ten years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases. Depreciation expense was $1.5 million in the year ended December 31, 2023 compared to $2.2 million in the year ended December 31, 2022 and $2.4 million in the year ended December 31, 2021.

Leases

We determine if an arrangement is a lease at the inception of the arrangement. We lease certain drilling or completion equipment, office space, field equipment, vehicles and other equipment under cancelable and non-cancelable leases to support our operations. Certain of our lease agreements include lease and non-lease components. We account for these components as a single lease. Lease costs associated with drilling and completion equipment are capitalized as part of well costs.

Lease right-of-use ("ROU") assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As most of our lease contracts do not provide an implicit discount rate, we use our incremental borrowing rate which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at our discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with a term of 12 months or less are not recorded as a right-of-use asset and liability. The majority of our leases are classified as either short-term or long-term operating leases.

Our leased assets may be used in joint oil and gas operations with other working interest owners. We recognize lease liabilities and ROU assets only when we are the signatory to a contract as an operator of joint properties. Such lease liabilities and ROU assets are determined and disclosed based on gross contractual obligations. Our lease costs are also presented on a gross contractual basis.

Other Assets

Investments in unaffiliated equity securities held in our deferred compensation plans qualify as trading securities and are recorded at fair value. Investments held in the deferred compensation plans consist of various publicly-traded mutual funds. These funds include equity securities and money market instruments and are reported in other assets in the accompanying consolidated balance sheets.

Other assets at December 31, 2023 include $72.0 million of marketable securities held in our deferred compensation plan, $7.3 million of deferred financing costs related to our bank credit facility and $9.7 million of investments and other. Other assets at December 31, 2022 included $57.7 million of marketable securities held in our deferred compensation plan and $10.4 million of investments and other.

Stock-based Compensation Arrangements

We account for stock-based compensation under the fair value method of accounting. We grant various types of stock-based awards including restricted stock and performance-based awards. The fair value of our restricted stock awards and our performance-based awards (where the performance condition is based on internal performance metrics) is based on the market value of our common stock on the date of grant. The fair value of our performance-based awards where the performance condition is based on market conditions is estimated using a Monte Carlo simulation method.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. If actual forfeitures are different than expected, adjustments to recognize expense may be required in future periods. To the extent possible, we limit the amount of shares to be issued for these awards by satisfying tax withholding requirements with cash. All awards have been issued at prevailing market prices at the time of grant and the vesting of these awards is based on an employee's continued employment with us, with the exception of employment termination due to death, disability or retirement. For additional information regarding stock-based compensation, see Note 10.

Derivative Financial Instruments

All of our commodity derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. While there is risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are important. Among these benefits are more consistent returns on invested capital and better access to bank and other capital markets, more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs. All unsettled commodity derivative instruments are recorded in the accompanying consolidated balance sheets as either an asset or a liability measured at their fair value. In most cases, our derivatives are reflected on our consolidated balance sheets on a net basis by brokerage firm when they are governed by master netting agreements, which in an event of default, allows us to offset payables to and receivables from the defaulting counterparty. Changes in a derivative's fair value are recognized in earnings. Cash flows from derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

All realized and unrealized gains and losses on derivative instruments are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value in the accompanying consolidated statements of income. Certain of our commodity derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. We have collars which establish a minimum floor price and a predetermined ceiling price. Our program may also include a three-way collar which is a combination of three options: a sold call, a purchased put and a sold put. The sold call establishes the ceiling price while the purchased put establishes the floor price until the market price for the commodity falls below the sold put stock price at which time the value of the purchased put is effectively capped. We have also entered into natural gas derivative instruments containing a fixed price swap and a sold option (which we refer to as a swaption). We have entered into basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into natural gas basis swap agreements that effectively fix our basis adjustments. For additional information regarding our derivative instruments, see Note 8.

From time to time, we may enter into derivative contracts and pay or receive premium payments at the inception of the derivative contract which represent the fair value of the contract at its inception. These amounts would be included within the net derivative asset or liability on our consolidated balance sheets. The amounts paid or received for derivative premiums reduce or increase the amount of gains and losses that are recorded in the earnings each period as the derivative contracts settle. We did not materially modify any existing derivative contracts in 2023, 2022 or 2021.

Concentrations of Credit Risk

As of December 31, 2023, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties' failure to perform under derivative contracts. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions, commodity traders and end-users in various industries and such receivables are generally unsecured. The nature of our customers' businesses may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions.

To manage risks of collecting accounts receivable, we monitor our counterparties' financial strength and/or credit ratings and where we deem necessary, we obtain parent company guarantees, prepayments, letters of credit or other credit enhancements to reduce risk of loss. We may also limit the level of exposure with any single counterparty. We do not anticipate a material impact on our financial results due to non-performance by third parties.

For the year ended December 31, 2023, we had one customer that accounted for 10% or more of natural gas, NGLs and oil sales compared to no such customers for the year ended December 31, 2022 and one customer for the year ended December 31, 2021. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil production.

We have executed International Swap Dealers Association Master Agreements ("ISDA Agreements") with counterparties for the purpose of entering into derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor counterparties based on assessment of their financial strength and/or credit ratings. Additionally, the terms of our ISDA Agreements provide us and our counterparties with netting rights such that we may offset payables against receivables with a counterparty under separate derivative contracts. Our ISDA Agreements also generally contain set-off rights such that, upon the occurrence of defined acts of default by either us or a counterparty to a derivative contract, the non-defaulting party may set-off receivables owed under all derivative contracts against payables from other agreements with that counterparty. None of our derivative contracts have a margin requirement or collateral provision that would require us to fund or post additional collateral prior to the scheduled cash settlement date.

At December 31, 2023, our derivative counterparties included fourteen financial institutions and commodity traders, of which all but six are secured lenders in our bank credit facility. At December 31, 2023, our net derivative asset includes a payable to one counterparty not included in our bank credit facility totaling $329,000 and a receivable from the remaining five counterparties of $26.4 million. In determining fair value of derivative assets, we evaluate the risk of non-performance and incorporate factors such as amounts owed under other agreements permitting set-off, as well as pricing of credit default swaps for the counterparty. Historically, we have not experienced any issues of non-performance by derivative counterparties. Net derivative liabilities are determined in part by using our market based credit spread to incorporate our theoretical risk of non-performance.

Asset Retirement Obligations

The fair value of asset retirement obligations ("ARO") is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing properties and include costs to dismantle and relocate or dispose of production platforms, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates of the cost to plug and abandon the wells in the future, federal and state regulatory requirements, inflation rates and credit-adjusted-risk-free interest rates. Depreciation of capitalized asset retirement costs will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. See Note 7 for additional information.

Exit Costs

We recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. The recognition and fair value estimation of an exit cost liability requires that management take into account certain estimates and assumptions. Fair value estimates are based on future discounted cash outflows required to satisfy the obligation. In periods subsequent to initial measurement, changes to an exit cost liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, are recognized as an adjustment to the liability in the period of the change utilizing the initial discount rate. These costs, including associated accretion expense, are included in exit costs in the accompanying consolidated statements of income. See Note 14 for additional information.

Contingencies

We are subject to legal proceedings, claims, and liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated. See Note 13 for a more detailed discussion regarding our contingencies.

Environmental Costs

Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. Expenditures that relate to an existing condition caused by past operations that have no future economic benefits are expensed.

Deferred Taxes

Deferred tax assets and liabilities, measured by the enacted tax rates, are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors may include whether we are in a cumulative loss position in recent years, our reversal of temporary differences and our expectation to generate sufficient taxable income in the periods before tax credits and operating loss carryforwards expire. All deferred taxes are classified as long-term in the accompanying consolidated balance sheets.

Treasury Stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

Adoption of New Accounting Standards

There have not been any new standards issued we consider material to our accounting or disclosures. There are no issued but pending standards expected to have a material impact on our consolidated financial statements.

(3) Revenues from Contracts with Customers

Disaggregation of Revenue

We have identified three material revenue streams in our business: natural gas sales, NGLs sales, crude oil and condensate sales. Brokered revenue attributable to each product sales type is included here because the volume of product that we purchase is subsequently sold to separate counterparties in accordance with existing sales contracts under which we also sell our production. Revenue attributable to each of our identified revenue streams is disaggregated below (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Natural gas sales	$ 1,234,308	$ 3,364,111	$ 1,896,231
NGLs sales	933,791	1,308,574	1,135,826
Oil and condensate sales	166,562	238,407	182,970
Total natural gas, NGLs and oil sales	2,334,661	4,911,092	3,215,027
Sales of purchased natural gas	195,656	408,584	342,431
Sales of purchased NGLs	1,834	2,783	6,925
Interest income	5,937	2,538	243
Other marketing revenue and other income	15,176	10,312	15,813
Total	$ 2,553,264	$ 5,335,309	$ 3,580,439

Performance Obligations and Contract Balance

A significant number of our product sales are short-term in nature with a contract term of one year or less. We typically satisfy our performance obligation upon transfer of control and record revenue in the month production is delivered to the purchaser. Settlement statements for certain gas and NGLs sales may be received 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts for product sales in the month that payment is received from the purchaser. We have internal controls in place for our estimation process and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the three years ended December 31, 2023, 2022 and 2021, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. Under our sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to our revenue contracts with customers was $263.9 million at December 31, 2023 compared to $463.3 million at December 31, 2022.

(4) Income Taxes

Our income tax expense was $229.2 million for the year ended December 31, 2023 compared to expense of $230.5 million in 2022 and a benefit of $9.7 million in 2021. The effective income tax rate is influenced by a variety of factors including geographic sources and relative magnitude of these sources of income. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2023	2022	2021
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
State, net of federal benefit	(0.1)	1.0	0.6
Equity compensation and executive compensation disallowance	(0.3)	0.2	2.6
Valuation allowances	0.2	(5.5)	(26.8)
Permanent differences and other	—	(0.4)	0.2
Consolidated effective tax rate	20.8 %	16.3 %	(2.4) %

Income tax expense (benefit) attributable to income before income taxes consists of the following (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Current			
Federal	$ —	$ —	$ —
State	1,547	14,688	7,984
	$ 1,547	$ 14,688	$ 7,984
Deferred			
Federal	$ 230,563	$ 245,839	$ 6,297
State	(2,909)	(30,067)	(24,024)
	227,654	215,772	(17,727)
Income tax expense (benefit)	$ 229,201	$ 230,460	$ (9,743)

Significant components of deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2023	2022
Deferred tax assets:		
Net operating loss carryforward	$ 538,340	$ 581,349
Divestiture contract obligation	107,067	105,227
Deferred compensation	17,342	25,733
Equity compensation	6,767	4,813
Asset retirement obligations	25,614	24,113
Interest expense carryforward	19,861	16,118
Lease right-of-use liabilities	6,023	19,395
Unrealized mark-to-market loss	—	30,307
Other	16,396	16,922
Valuation allowances:		
Federal	(23,396)	(21,320)
State, net of federal benefit	(172,001)	(171,423)
Total deferred tax assets	542,013	631,234
Deferred tax liabilities:		
Depreciation and depletion	(998,886)	(935,710)
Unrealized mark-to-market gain	(96,545)	—
Lease right-of-use assets	(5,184)	(18,440)
Other	(2,686)	(10,655)
Total deferred tax liabilities	(1,103,301)	(964,805)
Net deferred tax liability	$ (561,288)	$ (333,571)

At December 31, 2023, deferred tax liabilities exceeded deferred tax assets by $561.3 million. As of December 31, 2023, we have a state valuation allowance of $172.0 million related to state tax attributes in Louisiana, Oklahoma, Pennsylvania, Texas and West Virginia. As of December 31, 2023, we have federal valuation allowances of $23.4 million primarily related to our federal basis differences. The net change in our deferred tax asset valuation allowances was an increase of $2.7 million for the year ended December 31, 2023 compared to a reduction in our valuation allowances of $78.3 million in 2022 and a reduction of $108.0 million in 2021. We continue to evaluate the realizability of our federal and state deferred tax assets.

At December 31, 2023, we had federal NOL carryforwards of $1.8 billion. This includes $157.5 million that expires in 2037 and also includes $1.7 billion of NOL carryforwards generated after 2017 that do not expire. We have state NOL carryforwards in Pennsylvania of $811.1 million that expire between 2031 and 2042 and in Louisiana, we have state NOL carryforwards of $1.6 billion that do not expire. We file a consolidated tax return in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana and Pennsylvania and file consolidated or unitary state income tax returns in Oklahoma, Texas and West Virginia. We are subject to U.S. federal income tax examinations for the years 2020 and after and we are subject to various state tax examinations for years 2019 and after. We have not extended the statute of limitation period in any income tax jurisdiction. Our policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any material accrued interest or penalties related to tax amounts as of December 31, 2023 or December 31, 2022. Throughout 2023, 2022 and 2021, our unrecognized tax benefits were not material.

On July 12, 2022, the Commonwealth of Pennsylvania enacted legislation to reduce the corporate net income tax rate from 9.99% to 8.99% in 2023 and continues to reduce that rate by 0.5% per year beginning in 2024, with the rate becoming 4.99% in 2031 and each year thereafter.

(5) Net Income per Common Share

Basic income or loss per share attributable to common stockholders is computed as (i) income or loss attributable to common stockholders (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (i) basic income or loss attributable to common stockholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. Diluted net income or loss per share is calculated under both the two class method and the treasury stock method and the more dilutive of the two calculations is presented. The following table sets forth a reconciliation of net income or loss to basic income or loss attributable to common stockholders and to diluted income or loss attributable to common stockholders (in thousands except per share amounts):

	Year Ended December 31,		
	2023	2022	2021
Net income as reported	$ 871,142	$ 1,183,370	$ 411,778
Participating basic earnings [a]	(14,971)	(28,578)	(10,795)
Basic net income attributed to common stockholders	856,171	1,154,792	400,983
Reallocation of participating earnings [a]	159	614	272
Diluted net income attributed to common stockholders	$ 856,330	$ 1,155,406	$ 401,255
Net income per common share:			
Basic	$ 3.61	$ 4.79	$ 1.65
Diluted	$ 3.57	$ 4.69	$ 1.61

[a] Restricted stock Liability Awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Participating securities, however, do not participate in undistributed net losses.

The following table details basic weighted average common shares outstanding and diluted weighted average common shares outstanding (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Denominator:			
Weighted average common shares outstanding – basic	236,986	240,858	242,862
Effect of dilutive securities	2,851	5,521	6,452
Weighted average common shares outstanding – diluted	239,837	246,379	249,314

Weighted average common shares outstanding – basic excludes 4.1 million shares of restricted stock Liability Awards held in our deferred compensation plans (although all awards are issued and outstanding upon grant) for the period ended December 31, 2023 compared to 6.1 million shares for the period ended December 31, 2022 and 6.5 million shares for the period ended December 31, 2021. Equity grants of 3,000 for the year ended December 31, 2023 compared to 5,000 shares for the year ended December 31, 2022 and 18,000 shares for the year ended December 31, 2021 were outstanding but not included in the computation of diluted net income because the grant prices were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(6) Indebtedness

We had the following debt outstanding as of the dates shown below. The expenses of issuing debt are generally capitalized and included as a reduction to debt in the accompanying consolidated balance sheets. For December 31, 2023, deferred financing costs for our bank credit facility are included in other assets in the accompanying consolidated balance sheet. These costs are amortized over the expected life of the related instruments. When debt is retired before maturity, or modifications significantly change the cash flows, the related unamortized costs are expensed. No interest was capitalized in the three-year period ended December 31, 2023. The components of our debt outstanding, including the effects of debt issuance costs, is as follows (in thousands):

	December 31,	
	2023	2022
Bank debt	$ —	$ 19,000
Senior notes		
4.875% senior notes due 2025	688,388	750,000
8.25% senior notes due 2029	600,000	600,000
4.75% senior notes due 2030	500,000	500,000
Total senior notes	1,788,388	1,850,000
Total debt	1,788,388	1,869,000
Unamortized debt issuance costs	(14,159)	(27,040)
Total debt (net of debt issuance costs)	$ 1,774,229	$ 1,841,960

Bank Debt

In April 2022, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, and is secured by substantially all of our assets and has a maturity date of April 14, 2027. The bank credit facility provides for a maximum facility amount of $4.0 billion and an initial borrowing base of $3.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations and for event-driven unscheduled redeterminations. Our current bank group is composed of seventeen financial institutions. The borrowing base may be increased or decreased based on our request and sufficient proved reserves, as determined by the bank group. The commitment amount may be increased to the borrowing base, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. Borrowings under the bank facility can either be at the alternate base rate ("ABR," as defined in the bank credit agreement) plus a spread ranging from 0.75% to 1.75% or at the secured overnight financing rate ("SOFR", as defined in the bank credit agreement) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our SOFR loans to ABR loans or to convert all or any part of our ABR loans to SOFR loans. The weighted average interest rate was 8.4% for the year ended December 31, 2023 compared to 4.1% for the year ended December 31, 2022 and 2.1% for the year ended December 31, 2021. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2023, the commitment fee was 0.375%, the interest rate margin was 0.75% on our ABR loans and 1.75% on our SOFR loans.

On December 31, 2023, bank commitments totaled $1.5 billion and we had no outstanding borrowings under our bank credit facility. Additionally, we had $173.4 million of undrawn letters of credit leaving $1.3 billion of committed borrowing capacity available under the facility. As part of our redetermination completed in September 2023, our borrowing base was reaffirmed for $3.0 billion and our bank commitment was also reaffirmed at $1.5 billion.

Senior Note Redemptions

If we experience a change of control, noteholders may require us to repurchase all or a portion of our senior notes at 101% of the principal amount plus accrued and unpaid interest, if any. We currently intend to retire our outstanding long-term debt as it matures, is callable or when market conditions are favorable to repurchase in the open market.

In 2023, we repurchased in the open market $61.6 million principal amount of our 4.875% senior notes due 2025 at a discount. We recognized a gain on early extinguishment of debt of $438,000, net of the remaining deferred financing costs on the repurchased debt. Although we have no obligation to do so, we may continue, from time-to-time, to retire our outstanding debt through privately negotiated transactions, open market repurchases, redemptions or otherwise.

In January 2024, we repurchased in the open market $8.7 million aggregate to principal amount of our 4.875% senior notes due 2025 at a discount.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our wholly-owned subsidiaries, which are directly or indirectly owned by Range, of our senior notes and our bank credit facility are full and unconditional and joint and several, subject to certain customary release provisions. The assets, liabilities and results of operations of Range and our guarantor subsidiaries are not materially different than our consolidated financial statements. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or
- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain investments. We are required to maintain a ratio of debt-to-EBITDAX (as defined in the credit agreement) of less than 3.75x and a minimum current ratio (as defined in the credit agreement) of 1.0x. We were in compliance with applicable covenants under the bank credit facility at December 31, 2023. The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2023 (in thousands):

	Year Ended December 31,
2024	$ —
2025	688,388
2026	—
2027	—
2028	—
Thereafter	1,100,000
	$ 1,788,388

(7) Asset Retirement Obligations

ARO primarily represents the present value of the estimated amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well lives. The inputs are calculated based on historical data as well as current estimated costs. The following is a reconciliation of our liability for plugging and abandonment costs as of December 31, 2023 and 2022 (in thousands):

	Year Ended December 31,	
	2023	2022
Beginning of period	$ 109,851	$ 95,836
Liabilities incurred	2,047	2,589
Liabilities settled	(3,039)	(10,650)
Accretion expense	6,000	6,569
Change in estimate	2,570	15,507
End of period	117,429	109,851
Less current portion	(2,395)	(4,570)
Long-term asset retirement obligations	$ 115,034	$ 105,281

Accretion expense is recognized as an increase to depreciation, depletion and amortization expense in the accompanying consolidated statements of income.

(8) Derivative Activities

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swaps or collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Every derivative instrument is required to be recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Their fair value, which is represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price (generally NYMEX for natural gas and crude oil), approximated a net derivative asset of $424.4 million at December 31, 2023. These contracts expire monthly through December 2026. The following table sets forth the derivative volumes by year as of December 31, 2023, excluding our basis swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price			
			Swap	Sold Put	Floor	Ceiling
Natural Gas [a]						
2024	Swaps	304,973 Mmbtu/day	$ 4.01			
2024	Collars	436,694 Mmbtu/day			$ 3.50	$ 5.63
2024	Three-way Collars	93,511 Mmbtu/day		$ 2.50	$ 3.40	$ 4.15
2025	Swaps	400,000 Mmbtu/day	$ 4.12			
2025	Three-way Collars	30,000 Mmbtu/day		$ 2.70	$ 4.00	$ 5.00
2026	Swaps	60,000 Mmbtu/day	$ 4.15			
Crude Oil						
January-September 2024	Swaps	4,000 bbls/day	$ 80.25			
January-September 2024	Collars	832 bbls/day			$ 80.00	$ 90.12

[a] We also sold natural gas swaptions of 40,000 Mmbtu/day for calendar year 2026 at a weighted average price of $4.11/Mmbtu that expire June 2024.

Basis Swap Contracts

In addition to the commodity derivatives described above, at December 31, 2023, we had natural gas basis swap contracts which lock in the differential between NYMEX and certain of our physical pricing points in Appalachia. These contracts settle monthly through December 2026 and include a total volume of 313,453,000 Mmbtu. The fair value of these contracts was a net derivative asset of $18.3 million on December 31, 2023.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2023 and 2022 is summarized below (in thousands). As of December 31, 2023, we are conducting derivative activities with fourteen counterparties, of which all but six are secured lenders in our bank credit facility. We believe all of these counterparties are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements.

		December 31, 2023		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 238,465	$ —	$ 238,465
	–swaptions	—	(1,161)	(1,161)
	–collars	150,456	—	150,456
	–three-way collars	25,406	—	25,406
	–basis swaps	26,852	(8,246)	18,606
Crude oil	–swaps	9,115	—	9,115
	–collars	2,084	—	2,084
		$ 452,378	$ (9,407)	$ 442,971

		December 31, 2023		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaptions	$ (1,161)	$ 1,161	$ —
	–basis swaps	(8,575)	8,246	(329)
		$ (9,736)	$ 9,407	$ (329)

		December 31, 2022		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 19,438	$ (6,236)	$ 13,202
	–collars	54,222	(45,452)	8,770
	–three-way collars	12,424	(12,424)	—
	–basis swaps	25,493	(20,437)	5,056
Crude oil	–collars	1,807	—	1,807
Divestiture contingent consideration		13,080	—	13,080
		$ 126,464	$ (84,549)	$ 41,915

		December 31, 2022		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (115,374)	$ 6,236	$ (109,138)
	–collars	(72,866)	45,452	(27,414)
	–three-way collars	(24,341)	12,424	(11,917)
	–basis swaps	(24,972)	20,437	(4,535)
Crude oil	–swaps	(13,908)	—	(13,908)
		$ (251,461)	$ 84,549	$ (166,912)

The effects of our derivatives on our consolidated statements of income for the last three years are summarized below (in thousands).

	Year Ended December 31,		
Derivative Fair Value Income (Loss)	2023	2022	2021
Commodity swaps	$ 434,836	$ (713,122)	$ (466,203)
Swaptions	(1,161)	11,149	(1,346)
Collars	260,630	(302,364)	(117,612)
Three-way collars	88,096	(235,335)	(137,443)
Basis swaps	43,833	41,622	33,691
Calls	—	(1,363)	(836)
Freight swaps	—	(33)	(647)
Divestiture contingent consideration	(5,080)	10,940	40,180
Total	$ 821,154	$ (1,188,506)	$ (650,216)

(9) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. When transfers between levels occur, it is our policy to assume the transfer occurred at the date of the event or change in circumstances that caused the transfer.

Fair Values-Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

		Fair Value Measurements at December 31, 2023 Using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2023
Trading securities held in the deferred compensation plans		$ 71,989	$ —	$ —	$ 71,989
Derivatives	–swaps	—	247,580	—	247,580
	–collars	—	152,540	—	152,540
	–three-way collars	—	25,406	—	25,406
	–basis swaps	—	18,277	—	18,277
	–swaptions	—	—	(1,161)	(1,161)

	Fair Value Measurements at December 31, 2022 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2022
Trading securities held in the deferred compensation plans	$ 57,717	$ —	$ —	$ 57,717
Derivatives –swaps	—	(109,844)	—	(109,844)
–collars	—	(16,837)	—	(16,837)
–three-way collars	—	(11,917)	—	(11,917)
–basis swaps	—	521	—	521
Divestiture contingent consideration	—	13,080	—	13,080

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2023 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. Derivatives in Level 3 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes but will also utilize unobservable pricing inputs that are significant to overall value. As of December 31, 2023, a portion of our natural gas instruments contain swaptions where the counterparty has the right, but not the obligation, to enter into a fixed price swap on a pre-determined date. If exercised, the swaption contract becomes a swap treated consistently with our fixed-price swaps. At December 31, 2023, we used a weighted average implied volatility of 18% for our swaptions. The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	Year Ended December 31, 2023
Balance at December 31, 2022	$ —
Additions	(1,161)
Settlements	—
Transfers out of Level 3	—
Balance at December 31, 2023	$ (1,161)

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains or losses are included in deferred compensation plan expense in the accompanying consolidated statements of income. For the year ended December 31, 2023, interest and dividends were $1.6 million and mark-to-market was a gain of $7.8 million. For the year ended December 31, 2022, interest and dividends were $1.1 million and mark-to-market was a loss of $14.2 million. For the year ended December 31, 2021, interest and dividends were $951,000 and mark-to-market was a gain of $3.0 million.

Fair Values-Non-recurring

Certain assets are measured at fair value on a non-recurring basis. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. Our proved natural gas and oil properties are reviewed for impairment periodically as events or changes in circumstances indicate the carrying amount may not be recoverable. There were no proved property impairment charges for the three-year period ended December 31, 2023.

Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2023 and 2022 (in thousands):

	December 31, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$ 442,971	$ 442,971	$ 28,835	$ 28,835
Divestiture contingent consideration	—	—	13,080	13,080
Marketable securities [(a)]	71,989	71,989	57,717	57,717
(Liabilities):				
Commodity swaps, collars and basis swaps	(329)	(329)	(166,912)	(166,912)
Bank credit facility [(b)]	—	—	(19,000)	(19,000)
4.875% senior notes due 2025 [(b)]	(688,388)	(679,363)	(750,000)	(714,870)
8.25% senior notes due 2029 [(b)]	(600,000)	(624,816)	(600,000)	(618,312)
4.75% senior notes due 2030 [(b)]	(500,000)	(463,085)	(500,000)	(442,350)
Deferred compensation plan [(c)]	(117,125)	(117,125)	(189,241)	(189,241)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges and are updated based on end of period closing prices which is a Level 1 input.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior notes is based on end of period market quotes which are Level 2 inputs.

(c) The fair value of our deferred compensation plan is updated at the closing price on the balance sheet date which is a Level 1 input.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations, operating lease liabilities and the divestiture contract obligation that we incurred in conjunction with the sale of our North Louisiana assets.

(10) Stock-Based Compensation Plans

Description of the Plans

We have two active equity-based stock plans, our Amended and Restated 2005 Equity-Based Compensation Plan, which we refer to as the 2005 Plan and the Amended and Restated 2019 Equity-Based Compensation Plan, which we refer to as the 2019 Plan. Under these plans, the Compensation Committee of the board of directors may grant, various awards to non-employee directors and employees. Shares issued as a result of awards granted are generally new common shares but can be funded out of treasury shares, if available.

Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock and performance units. Unlike the other forms of stock-based compensation, the mark-to-market adjustment of the liability related to the vested restricted stock held in our deferred compensation plan is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the financial categories. The following details the allocation of stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2023 (in thousands):

	2023	2022	2021
Direct operating expense	$ 1,723	$ 1,459	$ 1,310
Brokered natural gas and marketing expense	2,095	2,439	1,794
Exploration expense	1,250	1,578	1,507
General and administrative expense	35,850	42,023	39,673
Total stock-based compensation	$ 40,918	$ 47,499	$ 44,284

In 2023, we recorded an additional tax benefit of an estimated $10.6 million for the tax effect of financial accounting expense compared to the corporate income tax deduction for equity compensation that vested during the year compared to additional tax benefit of $7.2 million in 2022 and additional tax benefit of $340,000 in 2021.

Stock-Based Awards

Restricted Stock Awards. We grant restricted stock units and restricted stock under our equity-based stock compensation plans to our employees, which we refer to as restricted stock Equity Awards. The restricted stock units generally vest over a three-year period and are contingent on the recipient's continued employment. Beginning in 2023, we began granting restricted stock (that was previously placed in our deferred compensation plan) that vests at the end of a three-year period for employee grants and at the end of a one-year period for non-employee directors. Vesting is also based upon the employee's continued employment with us. Prior to vesting, recipients of restricted stock typically earn dividends payable in cash upon vesting but they have no voting rights prior to vesting.

The Compensation Committee has granted restricted stock to certain employees and non-employee directors of the board of directors as part of their compensation. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, these shares were placed in our deferred compensation plan and, upon vesting, withdrawals are allowed in either cash or in stock. Compensation expense is recognized over the balance of the vesting period, which is typically at the end of three years for employee grants and at the end of a one-year period for non-employee directors. All Liability Awards were issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, Liability Awards recipients have the right to vote such stock and receive dividends thereon. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported in deferred compensation plan expense in the accompanying consolidated statements of income.

*Stock-Based Performance Awards - (PSUs)***.** We grant two types of performance share awards: one based on performance conditions measured against internal performance metrics and one based on market conditions measured based on Range's performance relative to a predetermined peer group ("TSR Awards").

Each unit granted represents one share of our common stock. These units are settled in stock and the amount of the payout is based on the vesting percentage, which can range from zero to 200%, and (1) the internal performance metrics achieved, which is determined by the Compensation Committee and (2) for our TSR Awards, the value of our common stock on the vesting date compared to our peers. Dividend equivalents accrue during the performance period and are paid in stock at the end of the performance period. The performance period is three years.

Restricted Stock – Equity Awards

In 2023, we granted 1.6 million restricted stock Equity Awards to employees which generally vest over a three-year period compared to 1.4 million in 2022 and 2.3 million in 2021. We recorded compensation expense for these outstanding awards of $31.6 million in the year ended December 31, 2023 compared to $21.0 million in 2022 and $19.6 million in 2021. The vesting date fair value of restricted stock Equity Awards which vested during 2023, 2022 and 2021 was $31.9 million, $20.3 million and $17.6 million. The weighted average grant date fair value of these Equity Awards was $22.82, $14.44 and $7.39 for awards unvested at December 31, 2023, 2022 and 2021. As of December 31, 2023, there was $31.2 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.7 years. These awards are not issued until such time as they are vested and the grantees do not have the option to receive cash.

Restricted Stock – Liability Awards

In 2023, we granted 13,000 shares of restricted stock Liability Awards as compensation to employees at a grant date fair value of $25.61 which generally vest at the end of a three-year period and 8,000 shares were granted to non-employee directors, at an average grant date fair value of $25.07 with vesting at the end of one year. In 2022, we granted 603,000 shares of restricted stock liability awards as compensation to employees at an average grant date value of $20.44 with vesting generally at the end of a three-year period and 47,000 shares were granted to non-employee directors at an average grant date fair value of $27.52 with vesting at the end of one year. In 2021, we granted 1.2 million shares of restricted stock liability awards of compensation to employees at an average grant date value of $9.31 with vesting generally at the end of a three year period and 102,000 shares were granted to non-employee directors at an average grant date fair value $12.49 with vesting at the end of one year. In 2023, the number of shares granted into our deferred compensation plan was reduced in favor of restricted stock Equity Awards. We recorded compensation expense for these restricted stock Liability Awards of $4.0 million in the year ended December 31, 2023 compared to $13.6 million in 2022 and $11.4 million in 2021. The vesting date fair value of these Liability Awards vested during 2023, 2022 and 2021 was $4.3 million, $13.2 million and $12.1 million. The weighted average grant date fair value of these Liability Awards was $19.44, $14.71 and $6.49 for awards unvested at December 31, 2023, 2022 and 2021. As of December 31, 2023, there was $1.0 million of unrecognized compensation related to restricted stock Liability Awards expected to be recognized over a weighted average period of less than one year. These awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported as deferred compensation expense in our consolidated statements of income (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan were $75.2 million in 2023 compared to $22.2 million in 2022 and $5.9 million in 2021.

Stock-Based Performance Awards

Internal Performance Metric Awards. These awards vest at the end of the three-year performance period. The performance metrics are set by the Compensation Committee. If the performance metric for the applicable period is not met, that portion is considered forfeited and there is an adjustment to the expense recorded.

Internal performance metric awards granted in 2023 and 2022 are earned based on:

- Net debt (total debt less cash on hand balance); and
- GHG emissions intensity.

Internal performance metric awards granted in 2021 are earned based on:

- Debt/EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense); and
- GHG emissions intensity.

In 2023, we granted 81,000 units as compensation to employees at a grant date fair value of $24.08 which vest at the end of a three-year period compared to 153,000 units at a grant date fair value of $20.38 in 2022 and 303,000 units at a grant date fair value of $9.81 in 2021. We recorded compensation expense for these awards of $2.2 million in the year ended December 31, 2023 compared to $6.2 million in the year ended December 31, 2022 and $6.6 million in the year ended December 31, 2021. As of December 31, 2023, there was $1.7 million of unrecognized compensation related to these internal performance metric awards to be recognized over a weighted average period of 1.9 years.

TSR awards. These awards are earned, or not earned, based on the comparative performance of Range's common stock measured against a predetermined group of companies in the peer group over a three-year performance period. The fair value of the TSR awards is estimated on the date of grant using a Monte Carlo simulation model which utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The fair value is recognized as stock-based compensation expense over the three-year performance period. Expected volatilities utilized in the model were estimated using a combination of a historical period consistent with the remaining performance period of three years and option implied volatilities. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the life of the grant. The following assumptions were used to estimate the fair value of the TSR awards granted during the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
	2023	2022	2021
Risk-free interest rate	3.8%	1.4%	0.2%
Expected annual volatility	61%	68%	75%
Grant date fair value per unit	$ 30.37	$ 27.90	$ 12.58

In 2023, we granted 64,000 units as compensation to employees which vest at the end of a three-year period compared to 112,000 in 2022 and 224,000 in 2021. We recorded TSR award compensation expense of $1.7 million in the year ended December 31, 2023 compared to $3.2 million in the year ended December 31, 2022 and $2.6 million in the year ended December 31, 2021. As of December 31, 2023, there was $1.7 million of unrecognized compensation related to these TSR awards to be recognized over a weighted average period of 1.9 years.

The following is a summary of the activity for our restricted stock and performance awards for the year ended December 31, 2023:

	Restricted Stock Equity Awards		Restricted Stock Liability Awards		Stock-Based Performance Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Number of Units [(a)]	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2022	1,736,688	$ 14.44	379,633	$ 14.71	1,950,632	$ 9.02
Granted	1,629,816	$ 25.11	21,170	$ 25.41	145,747	$ 26.86
Vested	(1,863,153)	$ 17.10	(307,687)	$ 14.01	(1,158,797)	$ 4.80
Forfeited	(29,546)	$ 17.73	—	$ —	—	$ —
Outstanding at December 31, 2023	1,473,805	$ 22.82	93,116	$ 19.44	937,582	$ 17.01

[(a)] Amounts granted reflect performance units initially granted. The actual payout will be between zero and 200% depending on achievement of either total stockholder return ranking compared to our peers at the vesting date or on the achievement of internal performance targets.

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. We match up to 6% of salary in cash and vesting of those contributions is immediate. In 2023, we contributed $5.2 million to the 401(k) Plan compared to $4.8 million in 2022 and $4.6 million in 2021. Employees have a variety of investment options in the 401(k) benefit plan.

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests at the end of three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of income. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market loss of $26.6 million in 2023 compared to a loss of $61.9 million in 2022 and a loss of $68.4 million in 2021. The Rabbi Trust held 1.6 million shares (1.5 million of vested shares) of Range stock at December 31, 2023 compared to 5.6 million (5.3 million of vested shares) at December 31, 2022.

(11) Capital Stock

We have authorized capital stock of 485.0 million shares, which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2022:

	Year Ended December 31,	
	2023	2022
Beginning balance	238,885,730	249,792,908
Restricted stock grants	50,238	671,303
Restricted stock units vested	1,755,345	1,827,625
Performance stock units vested	1,057,245	590,940
Performance stock dividends	6,276	1,843
Treasury shares	(714,530)	(13,998,889)
Ending balance	241,040,304	238,885,730

Common Stock Dividends

In January 2020, we announced that the board of directors had suspended our common stock dividend. The quarterly cash dividend was reinstated by our board of directors in third quarter 2022. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the board of directors and will depend on our financial condition, earnings, capital requirements, levels of indebtedness, our future business prospects and other matters our board of directors deems relevant. Our bank credit facility allows for the payment of common dividends, with certain limitations, as described in the facility agreement.

Stock Repurchase Program

In October 2019, the board of directors approved a stock repurchase program which was increased in size in 2022. Under this program, we may repurchase shares of our common stock in open market transactions, from time to time, in accordance with applicable SEC rules and federal securities laws. In 2023, we repurchased 715,000 shares at an aggregate value of $19.0 million. As of December 31, 2023, we have approximately $1.1 billion of remaining authorization under this program. The following is a schedule of the change in treasury shares since the beginning of 2022:

	Year Ended December 31,	
	2023	2022
Beginning balance	24,001,535	10,002,646
Rabbi trust shares distributed and/or sold	(470)	(1,111)
Shares repurchased	715,000	14,000,000
Ending balance	24,716,065	24,001,535

(12) Supplemental Cash Flow Information

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes paid to taxing authorities	$ (2,200)	$ (20,335)	$ (7,061)
Interest paid	(120,631)	(193,732)	(196,750)
Non-cash investing and financing activities included:			
Asset retirement costs capitalized, net	$ 4,616	$ 18,096	$ 18,634
Increase (decrease) in accrued capital expenditures	4,403	1,966	(4,505)

(13) Commitments and Contingencies

Litigation

We are the subject of, or party to, a number of pending or threatened legal actions and administrative proceedings or investigations arising in the ordinary course of our business including, but not limited to, royalty claims, contract claims and environmental claims. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations.

When deemed necessary, we establish reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible we could incur additional losses with respect to those matters in which reserves have been established. We will continue to evaluate our litigation on a quarterly basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

We have incurred and will continue to incur capital, operating and remediation expenditures as a result of environmental laws and regulations. As of December 31, 2023 and 2022, liabilities for remediation were not material. We are not aware of any environmental claims existing as of December 31, 2023 that have not been provided for or would otherwise have a material impact on our financial position or results of operations. Environmental liabilities normally involve estimates that are subject to revision until final resolution, settlement or remediation occurs. We believe that substantially all of our competitors must comply with similar environmental laws and regulations.

Obligations Following Divestitures

Certain contractual obligations were retained by us after our divestiture of our North Louisiana assets in 2020. These obligations are primarily related to gathering, processing and transportation agreements including certain minimum volume commitments. For additional information see Note 14.

Lease Commitments

The components of our total lease expense for the two years ended December 31, 2023, the majority of which is included as part of natural gas and oil properties on our consolidated balance sheets, are as follows (in thousands):

	Year Ended December 31,	
	2023	2022
Operating lease cost	$ 70,781	$ 37,873
Variable lease expense (1)	25,529	22,082
Short-term lease expense (2)	708	1,807
Sublease income	—	(137)
Total lease expense	$ 97,018	$ 61,625
Short-term lease costs (3)	$ 14,032	$ 17,285

(1) Variable lease payments that are not dependent on an index or rate and are not included in the lease liability or ROU assets.

(2) Short-term lease expense represents expense related to leases with a contract term of one year or less and are not included in our ROU assets or lease liability in our consolidated balance sheets.

(3) These short-term lease costs are related to leases with a contract term of one year or less, the majority of which are related to drilling rigs which are capitalized as part of natural gas and oil properties on our consolidated balance sheets and may fluctuate based on the number of drilling rigs being utilized.

Supplemental cash flow information related to our operating leases is included in the table below (in thousands):

	Year Ended December 31, 2023	2022
Cash paid for amounts included in the measurement of lease liabilities	$ 71,669	$ 37,457
ROU assets added in exchange for lease obligations	$ 7,421	$ 78,574

Supplemental balance sheet information related to our operating leases is included in the table below (in thousands):

	Year Ended December 31, 2023	2022
Operating lease ROU assets	$ 23,821	$ 84,070
Accrued liabilities – current	$ (11,584)	$ (67,493)
Operating lease liabilities – long-term	$ (16,064)	$ (20,903)

Our weighted average remaining lease term and weighted average discount rate for our operating leases are as follows:

	Year Ended December 31, 2023	2022
Weighted average remaining lease term	2.9 years	2.0 years
Weighted average discount rate	7%	6%

Our lease liabilities with enforceable contract terms that are greater than one year mature as follows (in thousands):

	Operating Leases
2024	$ 13,119
2025	7,921
2026	6,866
2027	2,698
2028	29
Total lease payments	30,633
Less effects of discounting	(2,985)
Total lease liability	$ 27,648

In late 2023, we entered into two-year commitments for drilling and completions equipment with gross lease payments of approximately $152.0 million. These leases are effective January 1, 2024 and will be recognized on our balance sheet as a lease in 2024.

Transportation, Gathering and Processing Contracts

We have entered into firm transportation and gathering contracts with various pipeline carriers for the future transportation and gathering of natural gas, NGLs and oil production from our properties in Pennsylvania. Under these contracts, we are obligated to transport or gather minimum daily natural gas volumes or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is currently expected to exceed the minimum daily volumes provided in the contracts. However, if in the future we fail to deliver the committed volumes, we would recognize a deficiency payment in the period in which the under-delivery takes place and the related liability has been incurred. As of December 31, 2023, future minimum transportation and gathering fees under our commitments are as follows (in thousands):

	Transportation and Gathering Contracts [a]
2024	$ 801,694
2025	730,907
2026	670,692
2027	616,260
2028	565,707
Thereafter	2,504,906
	$ 5,890,166

[a] The amounts in this table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest which can vary based on volumes produced.

In addition to the amounts included in the above table, we have entered into an additional agreement which modifies existing contracts that are included in the table above but are contingent on additional facility construction. This agreement is expected to begin in 2024 with a twelve-year term and adds to our ability to efficiently flow production volumes. The revised agreement covers 650,000 mcf per day but declines in the last five years of the contract ending at 300,000 mcf per day.

Not included in the table above is our estimate of accrued contractual obligations retained by us after our divestiture of our North Louisiana assets. These contractual obligations are related to gathering, processing and transportation agreements including certain minimum volume commitments. There are inherent uncertainties surrounding the retained obligation and, as a result, the determination of the accrued obligation required significant judgment and estimation. The actual settlement amount and timing may differ from our estimates. See also Note 14 for more information. As of December 31, 2023, the carrying value of this obligation was $397.4 million and is included in divestiture contract obligation in our consolidated balance sheets. As of December 31, 2023, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

	Divestiture Contract Obligation
2024	$ 86,762
2025	77,418
2026	61,805
2027	52,622
2028	48,116
Thereafter	70,727
	$ 397,450

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale properties. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third-party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2023, our delivery commitments through 2037 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2024	302,404	70,000
2025	282,493	54,932
2026	200,548	50,000
2027	100,000	46,233
2028	100,000	45,000
2029	100,000	33,444
2030	—	30,000
2031	—	16,575
2032-2037	—	10,000 (each year)

Other

We have lease acreage that is generally subject to expiration if initial wells are not drilled within a specified period, generally between three and five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs. We also regularly provide letters of credit in the normal course of business under certain contracts that may be drawn if we fail to perform under those contracts.

(14) Exit Costs

Exit Costs

In August 2020, we sold our North Louisiana assets and retained certain gathering, transportation and processing obligations which extend into 2030. These are contracts where we will not realize any future benefit. The estimated obligations are included in current and long-term divestiture contract obligation in our consolidated balance sheets. In the twelve months ended December 31, 2023, we recorded accretion expense of $41.9 million compared to $43.6 million in 2022 and $47.9 million in 2021. In second quarter 2023, we recorded a net adjustment of $37.8 million to increase this obligation primarily for higher rates due to inflation. In fourth quarter 2023, we recorded an additional $18.0 million adjustment to increase the obligation for a change to our forecasted drilling plans of the buyer along with adjusting for the difference between estimated and actual payments. In 2022, we recorded a net adjustment of $26.2 million to increase this obligation for a change in our forecasted drilling plans of the buyer along with adjusting the difference between estimated and actual payments. The present value of our estimated obligations related to these assets was initially recorded in 2020 as an exit cost at a total of $479.8 million. The estimated discounted value for this divestiture contract obligation was $397.4 million at December 31, 2023.

In second quarter 2020, we negotiated capacity releases on certain transportation pipelines in Pennsylvania effective May 31, 2020 and extending through the remainder of the contract. As a result of these releases, we recorded exit costs of $10.4 million which represented the discounted present value of our remaining obligations to the third party. The remaining carrying value for these transportation capacity releases as of December 31, 2023 was $2.5 million.

The following summarizes our exit costs for the three years ended December 31, 2023, 2022 and 2021 (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Severance costs	$ —	$ —	$ 567
Transportation contract capacity releases (including accretion of discount)	345	579	754
Divestiture contract obligation (including accretion of discount)	99,595	69,758	20,340
Total exit costs	$ 99,940	$ 70,337	$ 21,661

The following details the accrued exit cost liability activity for the years ended December 31, 2023 and 2022 (in thousands):

	Exit Costs	Termination Costs
Balance at December 31, 2021	$ 423,742	$ 10
Accrued contract obligations-changes in estimate	26,183	—
Accretion of discount	44,154	—
Payments	(98,399)	(10)
Balance at December 31, 2022	395,680	$ —
Accrued contract obligations-changes in estimate	57,735	—
Accretion of discount	42,205	—
Payments	(95,631)	—
Balance at December 31, 2023	$ 399,989	$ —

(15) Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

Our natural gas and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	December 31, 2023	2022	2021
		(in thousands)	
Natural gas and oil properties:			
Properties subject to depletion	$ 10,435,611	$ 9,855,287	$ 9,338,236
Unproved properties	789,871	800,592	837,334
Total	11,225,482	10,655,879	10,175,570
Accumulated depreciation, depletion and amortization	(5,107,801)	(4,765,475)	(4,420,914)
Net capitalized costs	$ 6,117,681	$ 5,890,404	$ 5,754,656

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [(a)]

	December 31, 2023	2022	2021
		(in thousands)	
Acquisitions:			
Acreage purchases	$ 40,067	$ 28,735	$ 21,942
Development	568,484	460,668	381,753
Exploration:			
Drilling	—	—	6,329
Expense	25,280	25,194	22,048
Stock-based compensation expense	1,250	1,578	1,507
Gas gathering facilities:			
Development	3,123	1,466	3,402
Subtotal	638,204	517,641	436,981
Asset retirement obligations	4,616	18,096	18,634
Total costs incurred	$ 642,820	$ 535,737	$ 455,615

(a) Includes cost incurred whether capitalized or expensed.

Reserves Audit

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. At year-end 2023, Netherland, Sewell & Associates, Inc., an independent petroleum consultant, conducted an audit of our 2023 reserves in Appalachia. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2023, our consultant audited approximately 96% of our proved reserves. A copy of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical professional at our independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished during the reserves audit process. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultant to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves any significant changes to our proved reserves. We provide historical information to our consultant for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. The reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared lease-by-lease, field-by-field or area-by-area, some of our estimates may be greater and some may be less than the estimates of our reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been approximately 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. Mr. Alan Farquharson, our Senior Vice President of Reservoir Engineering and Economics, holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than forty years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

Estimated Quantities of Proved Oil and Gas Reserves

Reserves of natural gas, NGLs, crude oil and condensate are estimated by our petroleum engineering staff and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, production taxes and other economic factors.

The SEC defines proved reserves as those volumes of natural gas, NGLs, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2023 to estimate reserve information were $68.32 per barrel of oil, $24.91 per barrel of NGLs and $2.20 per mcf for gas using a benchmark (NYMEX) of $78.10 per barrel and $2.62 per Mmbtu. The average realized prices used at December 31, 2022 to estimate reserve information were $87.14 per barrel of oil, $38.35 per barrel of NGLs and $6.08 per mcf for gas using a benchmark (NYMEX) of $94.13 per barrel and $6.36 per Mmbtu. The average realized prices used at December 31, 2021 to estimate reserve information were $59.35 per barrel of oil, $28.41 per barrel of NGLs and $3.30 per mcf for gas using a benchmark (NYMEX) of $66.34 per barrel and $3.60 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil and Condensate (Mbbls)	Natural Gas Equivalents (Mmcfe) [a]
Proved developed and undeveloped reserves:				
Balance, December 31, 2020	11,148,560	951,466	57,626	17,203,114
Revisions	(311,410)	16,845	(7,089)	(252,876)
Extensions, discoveries and additions	1,155,952	69,367	5,103	1,602,769
Production	(541,021)	(36,373)	(3,044)	(777,523)
Balance, December 31, 2021	11,452,081	1,001,305	52,596	17,775,484
Revisions	(393,165)	(20,251)	(12,885)	(591,983)
Extensions, discoveries and additions	1,278,499	59,296	5,661	1,668,244
Production	(539,443)	(36,392)	(2,716)	(774,089)
Balance, December 31, 2022	11,797,972	1,003,958	42,656	18,077,656
Revisions	326,783	44,515	2,485	608,784
Extensions, discoveries and additions	24,078	30,234	296	207,260
Production	(538,085)	(37,940)	(2,475)	(780,575)
Balance, December 31, 2023	11,610,748	1,040,767	42,962	18,113,125
Proved developed reserves:				
December 31, 2021	6,809,849	577,506	23,833	10,417,887
December 31, 2022	7,230,313	594,931	22,213	10,933,180
December 31, 2023	7,631,202	629,379	21,396	11,535,852
Proved undeveloped reserves:				
December 31, 2021	4,642,232	423,798	28,762	7,357,597
December 31, 2022	4,567,659	409,027	20,443	7,144,476
December 31, 2023	3,979,546	411,388	21,566	6,577,273

(a) Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

During 2023, revisions of previous estimates of a positive 608.8 Bcfe include a positive revision of 280.2 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan and positive performance revisions of 701.4 Bcfe due to improved well performance and longer lateral lengths partially offset by negative pricing revisions and 370.6 Bcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. We added approximately 207.3 Bcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale.

During 2022, we added approximately 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 77% of the 2022 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 592.0 Bcfe include a positive revision of 716.2 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan, positive performance revisions of 72.8 Bcfe and positive pricing revisions more than offset by 1.4 Tcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. These wells were removed due to the out-performance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations.

During 2021, we added approximately 1.6 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 72% of the 2021 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 252.9 Bcfe include positive performance revisions of 1.0 Tcfe and positive pricing revisions of 22.6 Bcfe more than offset by 1.3 Tcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon.

The following details the changes in proved undeveloped reserves for 2023 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2022	7,144,476
Undeveloped reserves transferred to developed	(937,906)
Revisions [(a)]	191,920
Extension and discoveries	178,783
Ending proved undeveloped reserves at December 31, 2023	6,577,273

(a) Includes 280.2 Bcfe positive revision for previously proved undeveloped properties due to their addition back into our five year development plan along with positive revisions for longer laterals offset by 370.6 Bcfe of proved undeveloped reserves removed and deferred due to the five-year rule which can be included in our future proved reserves as these locations are added back to our five-year development plan.

During 2023, we spent approximately $495.1 million on development costs related to proved undeveloped reserves that were transferred to developed reserves. Estimated future development costs of proved undeveloped reserves are projected to be approximately $2.6 billion. As of December 31, 2023, we have 90.2 Bcfe that have been reported for more than five years from their original date of booking, all of which are in the process of being completed and are expected to turn to sales in 2024. All of our recorded proved undeveloped drilling locations are scheduled to be drilled within five years of initial disclosure.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas, NGLs, crude oil and condensate reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas, NGLs and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs, crude oil and condensate, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. For the years ended 2023, 2022 and 2021, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas, NGLs and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas, NGLs and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas, NGLs and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas, NGLs, crude oil and condensate reserves is as follows and excludes cash flows associated with derivatives outstanding at each of the respective reporting dates. Future cash inflows are net of third-party transportation, gathering and compression expense.

	As of December 31, 2023	As of December 31, 2022
	(in thousands)	
Future cash inflows	$ 54,389,915	$ 113,954,835
Future costs:		
Production	(29,663,691)	(31,991,109)
Development [(a)]	(2,978,183)	(3,313,724)
Future net cash flows before income taxes	21,748,041	78,650,002
Future income tax expense	(4,176,604)	(16,651,625)
Total future net cash flows before 10% discount	17,571,437	61,998,377
10% annual discount	(10,732,951)	(37,453,094)
Standardized measure of discounted future net cash flows	$ 6,838,486	$ 24,545,283

(a) 2023 includes $358.7 million of undiscounted future asset retirement costs as of December 31, 2023, using current estimates of future abandonment costs.

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	December 31, 2023	December 31, 2022	December 31, 2021
		(in thousands)	
Revisions of previous estimates:			
Changes in prices and production costs	$ (23,584,574)	$ 14,326,997	$ 11,600,850
Revisions in quantities	(131,078)	109,129	577,737
Changes in future development and abandonment costs	(123,529)	(524,847)	(53,818)
Net change in income taxes	3,920,556	(2,625,699)	(2,248,161)
Accretion of discount	2,955,359	1,486,783	298,077
Additions to proved reserves from extensions, discoveries and improved recovery	103,116	2,842,173	1,423,510
Natural gas, NGLs and oil sales, net of production costs	(1,100,908)	(3,550,632)	(1,934,254)
Actual development costs incurred during the period	574,646	471,877	399,681
Changes in timing and other	(320,385)	(475,724)	(424,718)
Net change for the year	(17,706,797)	12,060,057	9,638,904
Beginning of year	24,545,283	12,485,226	2,846,322
End of year	$ 6,838,486	$ 24,545,283	$ 12,485,226

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. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2023 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting during the three months ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. See "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting" which appear on pages F-2 and F-3, respectively, under Item 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

During the fourth quarter, no director or officer adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement" as each term is defined in Items 408(a) and 408 (c) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required in response to this item will be set forth in the Range Proxy Statement for the 2024 Annual Meeting of Stockholders to be held in May 2024 and is incorporated herein by reference.

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for the information about our executive officers.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer, or persons performing similar functions (as well as our directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our President and Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2024 Annual Meeting of Stockholders.

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

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2024 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2024 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2024 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) **1. and 2**. Financial Statements and Financial Statement Schedules - the financial statements and financial statement schedules listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. Exhibits - the exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K.

		Incorporated by Reference (File No. 001-12209)		
Exhibit Number	**Exhibit Description**	**Form**	**Exhibit**	**Filing Date**
3	**Articles of Incorporation and Bylaws**			
3.1	Restated Certificate of Incorporation of Range Resources Corporation	10-Q	3.1.1	5/5/2004
3.2	First Amendment to the Restated Certificate of Incorporation	10-Q	3.1	7/28/2005
3.3	Second Amendment to the Restated Certificate of Incorporation	10-Q	3.1	7/24/2008
3.4	Amended and Restated By-laws of Range Resources Corporation, as amended as of May 15, 2016	8-K	3.1	5/19/2016
4	**Instruments Defining the Rights of Security Holders, Including Indentures, and Description of Registrant's Securities**			
4.1*	Description of Registrant's Securities			
4.2	Form of 4.875% Senior Notes due 2025	8-K	4.1	5/14/2015
4.3	Indenture dated May 14, 2015 among Range Resources Corporation, as issuer, the Initial Guarantors (as defined therein) and U.S. Bank National Association, as trustee	8-K	4.1	5/14/2015
4.4	Second Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., dated as of August 23, 2016	8-K	4.2	8/25/2016
4.5	First Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and U.S. Bank National Association, dated as of August 23, 2016	8-K	4.3	8/25/2016
4.6	Form of 8.25% Senior Notes due 2029	8-K	4.1	1/8/2021
4.7	Indenture dated January 8, 2021 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee	8-K	4.1	1/8/2021
4.8	Form of 4.75% Senior Notes due 2030	8-K	4.2	2/1/2022
4.9	Indenture dated February 1, 2022, among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank Trust Company National Association, as trustee	8-K	4.1	2/1/2022
10	**Material Contracts**			
10.01	Seventh Amended and Restated Credit Agreement, dated April 14, 2022, among Range Resources Corporation, as borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and Letter of Credit Issuer or Lender from time-to-time party thereto	8-K	10.1	4/18/2022
10.02	Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees	10-K	10.02	2/27/2023
10.03	Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan	8-K	10.1	6/4/2009

Exhibit Number	Exhibit Description (continued)	Incorporated by Reference (File No. 001-12209) Form	Exhibit	Filing Date
10.04	First Amendment to the Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan	8-K	10.1	5/20/2010
10.05	Second Amendment to the Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan	8-K	10.1	5/19/2011
10.06+	Range Resources Corporation Amended and Restated 2019 Equity – Based Compensation Plan	DEF14A	A	4/1/2022
10.08*	Amended and Restated Range Resources Corporation Executive Change in Control Severance Benefit Plan			
10.10+	Form of Indemnification Agreement	8-K	10.6	2/17/2009
19.1*	Insider Trading Policy			
21*	Subsidiaries of Registrant			
22*	Subsidiary Guarantors			
23.1*	Consent of Independent Registered Public Accounting Firm			
23.2*	Consent of Netherland, Sewell & Associates, Inc., independent consulting engineers			
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002			
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002			
97*	Policy Relating to Recovery of Erroneously Awarded Compensation			
99.1*	Report of Netherland, Sewell & Associates, Inc., independent consulting engineers			
101.INS*	Inline XBRL Instance Document			
101.SCH*	Inline XBRL Inline Taxonomy Extension Schema with Embedded Linkbase Document			
104*	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)			

* Filed herewith
** Furnished herewith
\+ Management compensatory plan or arrangement

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.

RANGE RESOURCES CORPORATION

By: /s/ DENNIS L. DEGNER

Dennis L. Degner
Chief Executive Officer and President
(principal executive officer)

Dated: February 21, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Capacity	Date
/s/ DENNIS L. DEGNER **Dennis L. Degner**	Chief Executive Officer and President (principal executive officer)	February 21, 2024
/s/ MARK S. SCUCCHI **Mark S. Scucchi**	Executive Vice President and Chief Financial Officer (principal financial officer)	February 21, 2024
/s/ DORI A. GINN **Dori A. Ginn**	Senior Vice President, Controller and Principal Accounting Officer (principal accounting officer)	February 21, 2024
/s/ GREG G. MAXWELL **Greg G. Maxwell**	Chairman of the Board	February 21, 2024
/s/ BRENDA A. CLINE **Brenda A. Cline**	Director	February 21, 2024
/s/ MARGARET K. DORMAN **Margaret K. Dorman**	Director	February 21, 2024
/s/ JAMES M. FUNK **James M. Funk**	Director	February 21, 2024
/s/ CHARLES G. GRIFFIE **Charles G. Griffie**	Director	February 21, 2024
/s/ STEVEN D. GRAY **Steven D. Gray**	Director	February 21, 2024
/s/ REGINAL W. SPILLER **Reginal W. Spiller**	Director	February 21, 2024