NORTHERN OIL & GAS, INC.

FORM 10-Q
(Quarterly Report)

Filed 04/30/25 for the Period Ending 03/31/25

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Telephone	952-476-9800
CIK	0001104485
Symbol	NOG
SIC Code	1311 - Crude Petroleum and Natural Gas
Industry	Oil & Gas Exploration and Production
Sector	Energy
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2025

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

For the transition period from ____________ to____________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**95-3848122**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

4350 Baker Road – Suite 400
Minnetonka, Minnesota 55343
(Address of Principal Executive Offices)

(952) 476-9800
(Registrant's Telephone Number, Including Area Code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.001	NOG	New York Stock Exchange

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

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

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

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller Reporting Company ☐
	Emerging Growth Company ☐

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

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

As of April 28, 2025, there were 98,704,081 shares of our common stock, par value $0.001, outstanding.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of crude oil and natural gas:

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"*Boe*." A barrel of oil equivalent and is a standard convention used to express crude oil, NGL and natural gas volumes on a comparable crude oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or NGL.

"*Boepd.*" Boe per day.

"*Btu" or "British Thermal Unit*." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand Boe.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate or NGLs.

"*MMBoe*." One million Boe.

"*MMBtu*." One million British Thermal Units.

"*MMcf*." One million cubic feet of natural gas.

"*NGLs*." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

"*Basin*." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion.*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"*Conventional play.*" An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"*Developed acreage.*" Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Development well.*" A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential.*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"*Dry hole*." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well.*" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"*Extension well*." An extension well is a well drilled to extend the limits of a known reservoir.

"*Field*." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*." A layer of rock which has distinct characteristics that differs from nearby rock.

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

"*Held by operations.*" A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"*Held by production.*" A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"*Hydraulic fracturing*." The technique of improving a well's production by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"*Infill well.*" A subsequent well drilled in an established spacing unit of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Net acres.*" The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"*Net well.*" A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"*NYMEX*." The New York Mercantile Exchange.

"*OPEC.*" The Organization of Petroleum Exporting Countries.

"*Productive well*." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Recompletion*." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Reservoir*." A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Service well." A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"*Spacing*." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Stratigraphic test well.*" A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

"*Unconventional play.*" An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

"*Undeveloped acreage*." Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"*Unit*." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*West Texas Intermediate or WTI.*" A light, sweet blend of oil produced from the fields in West Texas.

"*Working interest*." The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"Workover." Operations on a producing well to restore or increase production.

Terms used to assign a present value to or to classify our reserves:

"*Developed Oil and Gas Reserves.*" Oil and natural gas reserves of any category that can be expected to be recovered 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.

"*Possible reserves.*" The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"*Pre-tax PV-10%" or "PV-10.*" The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"*Probable reserves.*" The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"*Proved developed non-producing reserves (PDNPs).*" Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"*Proved developed producing reserves (PDPs).*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"*Proved reserves*." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil, NGLs or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"*Proved undeveloped drilling location.*" A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*." 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 development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir or an analogous reservoir.

"Reserves." Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"*Standardized measure*." Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Undeveloped Oil and Gas Reserves.*" Oil and natural gas reserves of any category 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.

NORTHERN OIL AND GAS, INC.
FORM 10-Q

March 31, 2025

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PART I - FINANCIAL INFORMATION

Item 1. ***Condensed Financial Statements.***

NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS
(UNAUDITED)

(In thousands, except par value and share data)	**March 31, 2025**	**December 31, 2024**
Assets		
Current Assets:		
Cash and Cash Equivalents	$ 33,576	$ 8,933
Accounts Receivable, Net	409,624	389,673
Advances to Operators	10,586	12,291
Prepaid Expenses and Other	5,076	5,271
Derivative Instruments	52,904	46,525
Income Tax Receivable	9,846	38,050
Total Current Assets	521,612	500,743
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	10,566,985	10,307,376
Unproved	42,825	42,702
Other Property and Equipment	8,783	8,197
Total Property and Equipment	10,618,593	10,358,275
Less – Accumulated Depreciation, Depletion and Impairment	(5,480,999)	(5,276,105)
Total Property and Equipment, Net	5,137,594	5,082,170
Derivative Instruments	1,250	9,832
Acquisition Deposit	4,000	—
Other Noncurrent Assets, Net	10,158	11,077
Total Assets	$ 5,674,614	$ 5,603,822
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts Payable	$ 230,924	$ 202,866
Accrued Liabilities	273,435	290,792
Accrued Interest	26,637	25,992
Derivative Instruments	27,855	19,915
Other Current Liabilities	5,467	4,705
Total Current Liabilities	564,318	544,270
Long-term Debt, Net	2,310,500	2,369,294
Deferred Tax Liability	274,684	228,038
Derivative Instruments	73,908	93,606
Asset Retirement Obligations	46,975	45,907
Other Noncurrent Liabilities	2,148	2,272
Total Liabilities	$ 3,272,533	$ 3,283,387
Commitments and Contingencies		
Stockholders' Equity		

Common Stock, Par Value $.001; 270,000,000 Shares Authorized; 98,702,027 Shares Outstanding at 3/31/2025 99,113,645 Shares Outstanding at 12/31/2024	501	501
Additional Paid-In Capital	1,820,080	1,877,416
Retained Earnings	581,500	442,518
Total Stockholders' Equity	2,402,081	2,320,435
Total Liabilities and Stockholders' Equity	$ 5,674,614	$ 5,603,822

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
(UNAUDITED)

(In thousands, except share and per share data)	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024
Revenues		
Oil and Gas Sales	$ 576,952	$ 532,041
Gain (Loss) on Commodity Derivatives, Net	21,761	(138,531)
Other Revenues	3,385	2,838
Total Revenues	602,098	396,348
Operating Expenses		
Production Expenses	114,040	105,447
Production Taxes	36,069	51,210
General and Administrative Expenses	14,481	11,393
Depletion, Depreciation, Amortization and Accretion	205,690	173,958
Other Expenses	2,537	2,019
Total Operating Expenses	372,817	344,027
Income From Operations	229,281	52,321
Other Income (Expense)		
Interest Expense, Net of Capitalization	(43,850)	(37,925)
Loss on Unsettled Interest Rate Derivatives, Net	(144)	—
Other Income	500	56
Total Other Expense, Net	(43,494)	(37,869)
Income Before Income Taxes	185,787	14,452
Income Tax Expense	46,805	2,846
Net Income	$ 138,982	$ 11,606
Net Income Per Common Share – Basic	$ 1.41	$ 0.12
Net Income Per Common Share – Diluted	$ 1.39	$ 0.11
Weighted Average Common Shares Outstanding – Basic	98,559,724	100,442,472
Weighted Average Common Shares Outstanding – Diluted	99,992,487	101,636,132

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
(UNAUDITED)

(In thousands)	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024
Cash Flows from Operating Activities		
Net Income	$ 138,982	$ 11,606
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization, and Accretion	205,690	173,958
Amortization of Debt Issuance Costs	2,390	2,203
Amortization of Bond Premium/Discount on Long-term Debt	(281)	(284)
Deferred Income Taxes	46,646	2,760
Unrealized (Gain) Loss on Derivative Instruments	(9,555)	157,648
Stock-Based Compensation Expense	3,576	2,274
Other	(20)	2,316
Changes in Working Capital and Other Items:		
Accounts Receivable, Net	(19,951)	39,719
Prepaid and Other Expenses	835	(78)
Income Tax Receivable	28,204	—
Accounts Payable	15,818	2,641
Accrued Interest	645	1,793
Accrued Liabilities and Expenses	(5,553)	(4,409)
Net Cash Provided by Operating Activities	407,426	392,147
Cash Flows from Investing Activities		
Capital Expenditures on Oil and Natural Gas Properties	(259,971)	(407,006)
Acquisition Deposit	(4,000)	—
Purchases of Other Property and Equipment	(587)	(50)
Net Cash Used for Investing Activities	(264,558)	(407,056)
Cash Flows from Financing Activities		
Advances on Revolving Credit Facility	55,000	180,000
Repayments on Revolving Credit Facility	(115,000)	(78,000)
Repurchases of Common Stock	(15,005)	(20,007)
Restricted Stock Surrenders - Tax Obligations	(1,486)	(2,712)
Common Dividends Paid	(41,734)	(40,099)
Net Cash Provided by (Used for) Financing Activities	(118,225)	39,183
Net Increase in Cash and Cash Equivalents	24,643	24,273
Cash and Cash Equivalents - Beginning of Period	8,933	8,195
Cash and Cash Equivalents - End of Period	33,576	32,468

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF STOCKHOLDERS' EQUITY
(UNAUDITED)

(In thousands, except share data)	Common Stock		Additional Paid-In Capital	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
	Shares	Amount			
December 31, 2024	99,113,645	$ 501	$ 1,877,416	$ 442,518	$ 2,320,435
Share Based Compensation	139,175	—	3,576	—	3,576
Restricted Stock Forfeitures	(1,313)	—	(1)	—	(1)
Restricted Stock Surrenders - Tax Obligations	(50,380)	—	(1,486)	—	(1,486)
Repurchases of Common Stock	(499,100)	—	(15,155)	—	(15,155)
Common Stock Dividends Declared	—	—	(44,270)	—	(44,270)
Net Income	—	—	—	138,982	138,982
March 31, 2025	98,702,027	$ 501	$ 1,820,080	$ 581,500	$ 2,402,081

(In thousands, except share data)	Common Stock		Additional Paid-In Capital	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
	Shares	Amount			
December 31, 2023	100,761,148	$ 503	$ 2,124,963	$ (77,790)	$ 2,047,676
Share Based Compensation	139,873	—	2,296	—	2,296
Restricted Stock Surrenders - Tax Obligations	(71,548)	—	(2,712)	—	(2,712)
Acquisitions of Oil and Natural Gas Properties	107,657	—	3,737	—	3,737
Issuance of Common Stock in Exchange for Warrants	656,297	1	(1)	—	—
Repurchases of Common Stock	(549,356)	(1)	(20,206)	—	(20,207)
Common Stock Dividends Declared	—	—	(40,418)	—	(40,418)
Net Income	—	—	—	11,606	11,606
March 31, 2024	101,044,071	$ 503	$ 2,067,660	$ (66,183)	$ 2,001,980

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

NOTES TO CONDENSED FINANCIAL STATEMENTS
MARCH 31, 2025
(UNAUDITED)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "NOG," "our" and words of similar import), a Delaware corporation, is an independent energy company engaged as a non-operator in the acquisition, exploration, development and production of oil and natural gas properties in the United States, primarily in the Williston Basin, the Permian Basin, the Appalachian Basin, and the Uinta Basin. The Company's common stock trades on the New York Stock Exchange under the symbol "NOG".

The Company's principal business is crude oil and natural gas exploration, development, and production in the United States. The Company's primary strategy is investing in non-operated minority working and mineral interests in oil and natural gas properties, with a core area of focus in four premier basins within the United States.

NOTE 2 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These financial statements, which are unaudited, have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP"). Such information includes all adjustments (consisting of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial position, results of operations and cash flows for the interim periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for an entire year.

Certain information, accounting policies, and footnote disclosures normally included in the financial statements prepared in accordance with GAAP have been condensed or omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The condensed financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2024, which were included in the Company's 2024 Annual Report on Form 10-K for the fiscal year ended December 31, 2024.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The most significant estimates relate to proved crude oil and natural gas reserves, which include limited control over future development plans as a non-operator, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, acquisition date fair values of assets acquired and liabilities assumed, impairment of crude oil and natural gas properties, asset retirement obligations at initial recognition, and deferred income taxes.

Management's estimates and assumptions were based on historical data and consideration of future market conditions. Given the uncertainty inherent in any projection, actual results may differ from the estimates and assumptions used, and conditions may change, which could materially affect amounts reported in the unaudited condensed financial statements.

Recently Issued Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB") that are adopted by the Company as of the specified effective date, as applicable. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

In November 2024, the FASB issued ASU 2024-04 Debt - Debt With Conversion and Other Options (Subtopic 470-20): Induced Conversion of Convertible Debt Instruments. The objective of the standard is to improve the relevance and consistency in application of the induced conversion guidance in Subtopic 470-20, Debt with Conversion and Other Options. This standard will affect entities that settle convertible debt instruments for which the conversion privileges are changed to induce conversion. ASU 2024-04 is effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

In November 2024, the FASB issued ASU 2024-03 Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard requires disclosure, in the notes to financial statements, of specified information about certain costs and expenses. The objective of the standard is to provide disaggregated information about a public business entity's expenses to help investors better understand the components of an entity's expenses, which should enable investors to better assess an entity's prospects for future cash flows. ASU 2024-03 is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

In December 2023, the FASB issued ASU 2023-09 Income Taxes (Topic 740): Improvements to Income Tax Disclosures, which requires the Company to disclose disaggregated jurisdictional and categorical information for the tax rate reconciliation, income taxes paid and other income tax related amounts. This guidance is effective for annual periods beginning after December 15, 2024, with early adoption permitted. The adoption is expected to enhance the Company's Notes to the Financial Statements. The Company is currently evaluating the impact the new standard will have on its financial statements and related disclosures.

In October 2023, the FASB issued ASU 2023-06 Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative, which amends GAAP to include 14 disclosure requirements that are currently required under SEC Regulation S-X or Regulation S-K. Each amendment will be effective on the date on which the SEC removes the related disclosure requirement from SEC Regulation S-X or Regulation S-K. The Company is currently evaluating the impact the new standard will have on its financial statements and related disclosures.

Revenue Recognition

The Company's revenues are primarily derived from its interests in the sales of oil and natural gas production. The Company recognizes revenue from its interests in the sales of crude oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of the product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and natural gas are made under contracts which the third-party operators of the wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in trade receivables, net in the condensed balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received. Historically, differences have been insignificant. Accordingly, the variable consideration is not constrained.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient exemption, which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company's oil is typically sold at delivery points under contract terms that are common in our industry. The Company's natural gas produced is delivered by the well operators to various purchasers at agreed upon delivery points under a limited number of contract types that are also common in our industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators will remit payment to the Company for its share in the value of the oil and natural gas sold.

The Company reports volumes and revenues on a two-stream basis. Accordingly, the Company's disaggregated revenue has two primary sources: (i) oil sales and (ii) natural gas and NGL sales. Substantially all of the Company's sales come from four operating areas in the United States: the Williston Basin, the Permian Basin, the Appalachian Basin, and the Uinta Basin. The following table presents the disaggregation of the Company's oil revenues and natural gas and NGL revenues for the three months ended March 31, 2025 and 2024.

(In thousands)	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024
Oil Sales	$ 459,682	$ 465,679
Natural Gas and NGL Sales	117,270	66,362
Total	$ 576,952	$ 532,041

Concentrations of Market, Credit Risk and Other Risks

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company's receivables include amounts due, indirectly via the third-party operators of the wells, from purchasers of its crude oil and natural gas production. While certain of these customers, as well as third-party operators of the wells, are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations have been immaterial.

As a non-operator, 100% of the Company's wells are operated by third-party operating partners. As a result, the Company is highly dependent on the success of these third-party operators. If they are not successful in the exploration, development and production activities relating to the Company's leasehold interests, or are unable or unwilling to perform, the Company's financial condition and results of operations could be adversely affected. These risks are heightened in a low commodity price environment, which may present significant challenges to these third-party operators. The Company's third-party operators will make decisions in connection with their operations that may not be in the Company's best interests, and the Company may have little or no ability to exercise influence over the operational decisions of its third-party operators. For the three months ended March 31, 2025, the Company's top four operators made up 39% of total oil and natural gas sales, with one operator comprising more than 10% but less than 15%. For the three months ended March 31, 2024, the Company's top four operators made up 37% of total oil and natural gas sales, with one operator comprising more than 10% but less than 15%.

The Company faces concentration risk due to the fact that substantially all of its oil and natural gas revenue is sourced from a limited number of geographic areas of operations. As a result, the Company is disproportionately exposed to risks that affect one or more of those areas in the Williston Basin, the Permian Basin, the Appalachian Basin and the Uinta Basin.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its counterparties is generally high. In the normal course of business, letters of credit or parent guarantees may be required for counterparties which management perceives to have a higher credit risk.

Net Income Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income attributable to common stockholders (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income attributable to common stockholders by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include shares issuable upon exercise of stock warrants and vesting of restricted stock awards, and shares issuable upon conversion of the Convertible Notes (see Note 4). The number of potential common shares outstanding are calculated using the treasury stock or if-converted method.

In those reporting periods in which the Company has reported net income available to common stockholders, anti-dilutive shares generally are comprised of the restricted stock that has average unrecognized stock compensation expense greater than the average stock price. In those reporting periods in which the Company has a net loss, anti-dilutive shares are comprised of the impact of those number of shares that would have been dilutive had the Company had net income plus the number of common stock equivalents that would be anti-dilutive had the company had net income.

Restricted stock awards are excluded from the calculation of basic weighted average common shares outstanding until they vest. For restricted stock awards that vest based on achievement of performance and/or market conditions, the number of contingently issuable common shares included in diluted weighted-average common shares outstanding is based on the number of common shares, if any, that would be issuable under the terms of the arrangement if the performance and/or market conditions were met at the end of the reporting period, assuming the result would be dilutive.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three months ended March 31, 2025 and 2024 are as follows:

	Three Months Ended March 31,	
(In thousands, except share and per share data)	**2025**	**2024**
Net Income	$ 138,982	$ 11,606
Weighted Average Common Shares Outstanding:		
Weighted Average Common Shares Outstanding – Basic	98,559,724	100,442,472
Plus: Dilutive Effect of Restricted Stock and Common Stock Warrants	1,432,763	1,193,660
Weighted Average Common Shares Outstanding – Diluted	99,992,487	101,636,132
Net Income per Common Share:		
Basic	$ 1.41	$ 0.12
Diluted	$ 1.39	$ 0.11
Shares Excluded from EPS Due to Anti-Dilutive Effect:		
Restricted Stock	11,780	5,315

Supplemental Cash Flow Information

The following table reflects the Company’s supplemental cash flow information for the three months ended March 31, 2025 and 2024:

	Three Months Ended March 31,	
(In thousands)	**2025**	**2024**
Supplemental Cash Items:		
Cash Paid During the Period for Interest, Net of Amount Capitalized	$ 41,888	$ 35,981
Cash Paid (Refunded) During the Period for Income Taxes	(2,960)	(25)
Non-cash Investing Activities:		
Capital Expenditures on Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities	328,782	211,287
Capitalized Asset Retirement Obligations	890	1,890
Compensation Capitalized on Oil and Gas Properties	194	22
Non-cash Financing Activities:		
Issuance of Common Stock in Exchange for Warrants	—	23,338
Common Stock Dividends Declared, But Not Paid	44,270	40,418
Repurchases of Common Stock - Excise Tax	150	200

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The Company follows the full cost method of accounting to account for its crude oil and natural gas operations, whereby all costs related to the exploration and development of crude oil and natural gas properties are capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the Company's oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The Company did not have any impairment of its oil and natural gas properties for the three months ended March 31, 2025 and 2024. Average commodity prices have declined in recent months. If this downward trend continues, and/or if our proved reserves decrease significantly in future months, the present value of the Company's future net revenues could decline significantly, which could trigger the need for the Company to record a non-cash ceiling test impairment of its oil and natural gas property costs in future periods.

The book value of the Company's crude oil and natural gas properties consists of all acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying condensed statements of operations from the closing date of the acquisition.

2025 Acquisitions

During the three months ended March 31, 2025, the Company acquired oil and natural gas properties through a number of smaller independent transactions for a total of $4.8 million.

Subsequent to March 31, 2025, in April 2025, the Company completed its acquisition of certain oil and natural gas properties, interests and related assets in the Midland Permian basin from a private seller, effective June 1, 2024. The total consideration paid to the seller at closing, net to the Company, was approximately $61.7 million in cash, a portion of which was funded by a $4.0 million acquisition deposit paid in February 2025.

2024 Acquisitions

In addition to the closing of the Delaware Acquisition, as defined below, during the three months ended March 31, 2024, the Company acquired oil and natural gas properties through a number of smaller independent transactions for a total of $4.9 million.

Delaware Acquisition

In January 2024, the Company completed its acquisition of certain oil and natural gas properties, interests and related assets in the Delaware Basin from a private seller, effective as of November 1, 2023 (the "Delaware Acquisition").

The total consideration paid to the seller at closing included 107,657 shares of common stock and $147.8 million in cash, a portion of which was funded by a $17.1 million deposit paid at signing in November 2023.

The results of operations from the date of the Delaware Acquisition through March 31, 2024 represented approximately $11.2 million of revenue and $4.7 million of income from operations.

The Company accounted for the Delaware Acquisition as a business combination. Accordingly, transaction costs of approximately $0.6 million were included in general and administrative expense in the Company's statements of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	151,912
Total assets acquired		151,912
Asset retirement obligations		(380)
Net assets acquired	$	151,531
Fair value of consideration paid for net assets:		
Cash consideration	$	147,794
Non-cash consideration		3,737
Total fair value of consideration transferred	$	151,531

Point Acquisition

In September 2024, the Company completed its acquisition of certain oil and natural gas properties located in the Delaware Basin from Point Energy Partners, LLC ("Point"), effective as of April 1, 2024 (the "Point Acquisition"). At closing, the Company acquired a 20% undivided working interest in the assets sold by Point, with Vital Energy, Inc., an unaffiliated third party, acquiring the other 80% and becoming the operator of the acquired assets.

The total consideration paid to the seller at closing, net to the Company, was $205.1 million in cash, a portion of which was funded by a $22.0 million acquisition deposit paid in July 2024. As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $7.2 million subsequent to closing.

The Company accounted for the Point Acquisition as an asset acquisition, as substantially all of the fair value of the gross assets acquired were concentrated in a group of similar identifiable assets. Accordingly, approximately $2.8 million transaction costs were capitalized to the full cost pool of the oil and natural gas properties acquired.

XCL Acquisition

In October 2024, the Company completed its acquisition of certain oil and natural gas properties in the Uinta Basin from XCL Resources, LLC and certain affiliated entities ("XCL"), effective as of May 1, 2024 (the "XCL Acquisition"). At closing, the Company acquired a 20% undivided working interest in the assets sold by XCL, with SM Energy Company, an unaffiliated third party, acquiring the other 80% and becoming the operator of the acquired assets.

The total consideration paid to the seller at closing, net to the Company, was $511.3 million in cash, a portion of which was funded by a $25.5 million acquisition deposit paid in June 2024.
The Company accounted for the XCL Acquisition as an asset acquisition, as substantially all of the fair value of the gross assets acquired were concentrated in a group of similar identifiable assets. Accordingly, approximately $9.4 million transaction costs were capitalized to the full cost pool of the oil and natural gas properties acquired.

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion until the properties are evaluated for reserves. Once a property is evaluated, all associated acreage and drilling costs are subject to depletion.

The Company historically has acquired unproved properties by purchasing individual or small groups of leases directly from mineral owners, landmen, or lease brokers, which leases historically have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. The Company generally participates in drilling activities on a heads up basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

The Company believes that the majority of its unproved property will be evaluated, and thus the related costs will become subject to depletion within the next five years. The timing by which all unproved properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Capitalized costs associated with evaluated leasehold costs, which includes leases that have expired or have been deemed uneconomic, and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized using the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. The costs of unproved properties are withheld from the depletion base until such time that they are evaluated.

When unproved properties are evaluated, their cost is added to costs subject to depletion and full cost ceiling calculations. For the three months ended March 31, 2025 and 2024, unproved properties of $1.8 million and $1.1 million, respectively, were transferred to evaluated leasehold costs, due to lease expirations.

NOTE 4 LONG-TERM DEBT

The Company's long-term debt consists of the following:

	March 31, 2025			
(In thousands)	**Principal Balance**	**Premium/(Discount)**	**Debt Issuance Costs, Net**	**Long-term Debt, Net**
Revolving Credit Facility [1]	$ 630,000	$ —	$ —	$ 630,000
Senior Notes due 2028	705,108	5,846	(6,538)	704,416
Convertible Notes due 2029	500,000	—	(11,142)	488,858
Senior Notes due 2031	500,000	(5,494)	(7,280)	487,226
Total	$ 2,335,108	$ 352	$ (24,960)	$ 2,310,500

	December 31, 2024			
	Principal Balance	**Premium/(Discount)**	**Debt Issuance Costs, Net**	**Long-term Debt, Net**
Revolving Credit Facility [1]	$ 690,000	$ —	$ —	$ 690,000
Senior Notes due 2028	705,108	6,346	(7,097)	704,357
Convertible Notes due 2029	500,000	—	(11,780)	488,220
Senior Notes due 2031	500,000	(5,712)	(7,571)	486,717
Total	$ 2,395,108	$ 634	$ (26,448)	$ 2,369,294

(1) Debt issuance costs related to the Company's Revolving Credit Facility of $8.1 million and $9.0 million as of March 31, 2025 and December 31, 2024, are recorded in "Other Noncurrent Assets, Net" in the balance sheets.

Revolving Credit Facility

In June 2022, the Company entered into a Third Amended and Restated Credit Agreement (as amended, modified, or supplemented through the date of this filing, the "Revolving Credit Facility") with Wells Fargo Bank, National Association, as administrative agent and collateral agent ("Agent"), and the lenders from time to time party thereto, which amended and restated the Company's prior revolving credit facility that was entered into in November 2019. The Revolving Credit Facility is scheduled to mature on June 7, 2027.

The Revolving Credit Facility is comprised of revolving loans and letters of credit and is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries' (if any) oil and natural gas properties. As of March 31, 2025, the borrowing base was $1.8 billion and the aggregate elected commitment amount was $1.5 billion. The Company's borrowing availability under the Revolving Credit Facility is set at the lesser of the borrowing base and the elected commitment amount. The borrowing base will be redetermined semiannually on or around April 1 and October 1, with one interim "wildcard" redetermination available to each of the Company and the Agent (acting at the direction of the lenders holding at least two-thirds of commitments and loans outstanding under the Revolving Credit Facility) between scheduled redeterminations. Upon an acquisition of oil and natural gas properties with an aggregate value exceeding

5% of the borrowing base, the Company may request an additional redetermination. The Company has the option to seek commitments for term loans, which such term loans (if obtained) are capped at the least of (i) the borrowing base minus the aggregate elected commitment amount minus the then-outstanding principal amount of term loans, (ii) the aggregate elected commitment amount minus the then-outstanding principal amount of term loans and (iii) $500.0 million. Such term loans are subject to certain other terms of the Revolving Credit Facility.

At the Company's option, borrowings under the Revolving Credit Facility shall bear interest at the base rate or SOFR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the Agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 125 to 225 basis points, and the applicable margin for SOFR loans ranges from 225 to 325 basis points, in each case depending on the percentage of the borrowing base utilized.

The Revolving Credit Facility contains customary events of default and affirmative and negative covenants. In addition, the Revolving Credit Facility requires that the Company comply with the following financial covenants: (i) the Net Leverage Ratio (as defined in the Revolving Credit Facility) shall be no more than 3.50 to 1.00, and (ii) the Current Ratio (as defined in the Revolving Credit Facility) shall not be less than 1.00 to 1.00. The Company was in compliance with all applicable covenants as of March 31, 2025.

The Company's obligations under the Revolving Credit Facility are secured by mortgages on not less than 90% of the value of proven reserves associated with the oil and natural gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company's obligations under the Revolving Credit Facility are secured by a first priority security interest in substantially all of the Company's assets.

Senior Notes due 2028

In February 2021, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "2028 Notes Indenture"), pursuant to which the Company issued $550.0 million in aggregate principal amount of 8.125% senior notes due 2028 (the "Original 2028 Notes"). In November 2021, the Company issued an additional $200.0 million aggregate principal amount of 8.125% senior notes due 2028 (together with the Original 2028 Notes, the "Senior Notes due 2028"). The proceeds of the Senior Notes due 2028 were used primarily to refinance existing indebtedness, and for general corporate purposes.

During 2022, the Company repurchased and retired $25.8 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $24.9 million in cash, plus accrued interest. During 2023, the Company repurchased and retired $19.1 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $18.4 million in cash, plus accrued interest. As of March 31, 2025, the Company's liability under the 2028 Notes Indenture was approximately $705.1 million.

The Senior Notes due 2028 will mature on March 1, 2028. Interest is payable semi-annually in arrears on each March 1 and September 1 to holders of record on the February 15 and August 15 immediately preceding the related interest payment date, at a rate of 8.125% per annum. The Company may redeem all or a part of the Senior Notes due 2028 at redemption prices (expressed as percentages of principal amount) equal to 102.031% through February 28, 2026, and 100% beginning on March 1, 2026, plus accrued and unpaid interest to the redemption date.

If a Change of Control Triggering Event (as defined in the 2028 Notes Indenture) occurs, each holder of Senior Notes due 2028 may require the Company to repurchase all or any part of that holder's Senior Notes due 2028 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2028 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2028 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2028 Notes Indenture contains customary events of default and affirmative and negative covenants. As of March 31, 2025, the Company was in compliance with all applicable covenants.

Convertible Notes due 2029

In October 2022, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "Convertible Notes Indenture"), pursuant to which the Company issued $500.0 million in aggregate principal amount of 3.625% convertible senior notes due 2029 (the "Convertible Notes"). The proceeds of the Convertible Notes were used to refinance existing indebtedness and for other general corporate purposes. The Convertible Notes mature on April 15, 2029, unless earlier repurchased, redeemed or converted. The Convertible Notes accrue interest at a rate of 3.625% per annum, payable semi-annually in arrears on April 15 and October 15 of each year.

Before October 16, 2028, noteholders have the right to convert their Convertible Notes only upon the occurrence of certain events. From and after October 16, 2028, noteholders may convert their Convertible Notes at any time at their election until the close of business on the second scheduled trading day immediately before the maturity date. The Company will have the right to elect to settle conversions either entirely in cash or in a combination of cash and shares of its common stock. However, upon conversion of any Convertible Notes, the conversion value, which will be determined over a period of 40 trading days, will be paid in cash up to at least the principal amount of the Convertible Notes being converted. The initial conversion rate was 26.3104 shares of common stock per $1,000 principal amount of Convertible Notes, which represented an initial conversion price of approximately $38.01 per share of common stock. The conversion rate and conversion price are subject to customary anti-dilution and other adjustments upon the occurrence of certain events. As of March 31, 2025, the conversion rate was 26.9811 shares of common stock per $1,000 principal amount of Convertible Notes, which represented a conversion price of approximately $37.06 per share of common stock. In addition, if certain corporate events that constitute a “Make-Whole Fundamental Change” (as defined in the Convertible Notes Indenture) occur, then the conversion rate will, in certain circumstances, be increased for a specified period of time.

The Convertible Notes are redeemable, in whole or in part (subject to certain limitations), at the Company’s option at any time, and from time to time, on or after April 15, 2026 and on or before the 40th scheduled trading day immediately before the maturity date, at a cash redemption price equal to the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date, but only if the last reported sale price per share of the Company’s common stock exceeds 130% of the conversion price on (i) each of at least 20 trading days, whether or not consecutive, during the 30 consecutive trading days ending on, and including, the trading day immediately before the date the Company sends the related redemption notice; and (ii) the trading day immediately before the date the Company sends such notice. In addition, calling any Convertible Note for redemption will constitute a Make-Whole Fundamental Change with respect to that Convertible Note, in which case the conversion rate applicable to the conversion of that Convertible Note will be increased in certain circumstances if it is converted after it is called for redemption.

If certain corporate events that constitute a “Fundamental Change” (as defined in the Convertible Notes Indenture) occur, then, subject to a limited exception for certain cash mergers, noteholders may require the Company to repurchase their Convertible Notes at a cash repurchase price equal to the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, to, but excluding, the fundamental change repurchase date. The definition of Fundamental Change includes certain business combination transactions involving the Company and certain de-listing events with respect to the Company’s common stock.

The Convertible Notes Indenture contains customary events of default and affirmative and negative covenants. As of March 31, 2025, the Company was in compliance with all applicable covenants.

Capped Call Transactions

In October 2022, in connection with the Convertible Notes offering described above, the Company entered into privately negotiated capped call transactions (the “Capped Call Transactions”) with certain of the initial purchasers of the Convertible Notes and/or their respective affiliates and/or other financial institutions. The Company paid $36.1 million in total consideration to enter into the Capped Call Transactions. The Capped Call Transactions cover, subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the Convertible Notes, the number of shares of common stock initially underlying the Convertible Notes. The Capped Call Transactions are expected generally to reduce potential dilution to the common stock upon any conversion of Convertible Notes and/or offset any potential cash payments the Company is required to make in excess of the principal amount of such converted Convertible Notes, as the case may be, with such reduction and/or offset subject to a cap. The cap price of the Capped Call Transactions was initially approximately $52.17 per share of common stock, which represents a premium of 75% over the last reported sale price of the common stock of $29.81 per share on October 11, 2022, and is subject to certain customary adjustments under the terms of the Capped Call Transactions. As of March 31, 2025, the cap price of the Capped Call Transactions was approximately $50.87 per share of common stock.

Senior Notes due 2031

In May 2023, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the “2031 Notes Indenture”), pursuant to which the Company issued $500.0 million in aggregate principal amount of the Company’s 8.750%

senior notes due 2031 (the "Senior Notes due 2031"). The proceeds of the Senior Notes due 2031 were used primarily to refinance existing indebtedness, and for general corporate purposes.

The Senior Notes due 2031 will mature on June 15, 2031. Interest is payable semi-annually in arrears on each June 15 and December 15, to holders of record on the June 1 and December 1 immediately preceding the related interest payment date, at a rate of 8.750% per annum. Prior to June 15, 2026, the Company may redeem up to 35% of the aggregate principal amount of Senior Notes due 2031, upon not less than 10 or more than 60 days' notice, at a redemption price of 108.750% of the principal amount of the Senior Notes due 2031 redeemed, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date), in an amount not greater than the net cash proceeds of one or more equity offerings by the Company, provided that (i) at least 65% of the aggregate principal amount of Senior Notes due 2031 issued under the 2031 Notes Indenture (including any Additional Notes (as defined in the 2031 Notes Indenture) but excluding the Senior Notes due 2031 held by the Company and its Subsidiaries (as defined in the 2031 Notes Indenture)) remains outstanding immediately after the occurrence of such redemption (unless all Senior Notes due 2031 are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days of the date of the closing of each such equity offering. In addition, prior to June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031, on any one or more occasions, upon not less than 10 or more than 60 days' notice, at a redemption price equal to 100% of the principal amount of the Senior Notes due 2031 redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date).

On or after June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031 at redemption prices (expressed as percentages of principal amount) equal to 104.375% for the twelve-month period beginning on June 15, 2026, 102.188% for the twelve-month period beginning on June 15, 2027, and 100% beginning on June 15, 2028, plus accrued and unpaid interest to the redemption date.

If a Change of Control Triggering Event (as defined in the 2031 Notes Indenture) occurs, each holder of Senior Notes due 2031 may require the Company to repurchase all or any part of that holder's Senior Notes due 2031 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2031 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2031 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2031 Notes Indenture contains customary event of default and certain affirmative and negative covenants. As of March 31, 2025, the Company was in compliance with all applicable covenants.

NOTE 5 COMMON AND PREFERRED STOCK

Common Stock

On May 23, 2024, the Company filed an amendment to its certificate of incorporation, which was effective upon filing, to increase the number of authorized shares of common stock, par value $0.001 per share, from 135,000,000 to 270,000,000, as approved by the Company's stockholders at the 2024 Annual Meeting of Stockholders on May 23, 2024. As of March 31, 2025, the Company had 98,702,027 shares of common stock issued and outstanding.

Preferred Stock

The Company is authorized to issue up to 5,000,000 shares of preferred stock, par value $0.001 per share, with such designations, voting and other rights and preferences as may be determined from time to time by the Company's board of directors. As of March 31, 2025, the Company had zero shares of preferred stock issued and outstanding.

2025 Activity

Common Stock

During the three months ended March 31, 2025, 50,380 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with the vesting of their restricted stock awards. The total value of these shares surrendered, based on the market prices on the dates the shares were surrendered, was approximately $1.5 million.

During the three months ended March 31, 2025, 1,313 shares of the Company's stock, previously issued as stock-based compensation, were forfeited by a former employee of the Company upon separation.

During the three months ended March 31, 2025, the Company issued 139,175 shares of its common stock to executive officers, employees, and directors as stock-based compensation (see Note 6).

Dividends

In January 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend is payable on April 30, 2025, to stockholders of record as of the close of business on March 28, 2025.

On April 29, 2025, the Company's board of directors declared a cash dividend on the Company's common stock in the amount of $0.45 per share. The dividend is payable on July 31, 2025, to stockholders of record as of the close of business on June 27, 2025.

Stock Repurchase Program

In May 2022, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. In July 2024, the Company's board of directors terminated the prior stock repurchase program, which was substantially depleted, and approved a new stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. In March 2025, the Company's board of directors approved a $100.0 million increase to the authorization under this stock repurchase program. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

During the three months ended March 31, 2025, the Company repurchased 499,100 shares of its common stock for $15.2 million (including commissions and excise taxes) under the stock repurchase program.

The Company's accounting policy upon the repurchase of shares is to deduct its par value from common stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital. All repurchased shares are included in the Company's pool of authorized but unissued shares.

NOTE 6 STOCK-BASED COMPENSATION AND WARRANTS

Stock-Based Compensation

The Company maintains the Amended and Restated 2018 Equity Incentive Plan (the "2018 Plan") for the purpose of making equity-based awards to employees, directors and other eligible persons. As of March 31, 2025, there were 2,641,505 shares available for future awards or settlement of awards under the 2018 Plan.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative expenses" line item in the condensed statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Oil and natural gas properties" line item in the condensed balance sheets.

Issuances made pursuant to the 2018 Plan are summarized as follows:

The Company issues share-based awards in the form of restricted stock awards ("RSAs"), restricted stock units ("RSUs") and share appreciation awards ("SARs"), subject to various vesting conditions, as compensation to executive officers, employees and directors of the Company. Typically, RSAs issued to employees and executive officers contain a service condition only and generally vest over three or four years. Typically, RSUs and SARs contain both a service and market condition. Market conditions can be the Company's absolute total shareholder return ("TSR"), the Company's TSR ranking among its peer companies or the Company's market capitalization growth measured over a defined performance period. Grantees' continued employment through the end of the performance period is required for such RSUs and SARs to vest. RSAs issued to directors generally vest either immediately or over one year, subject to continued service and provided that any performance and/or market conditions are also met.

For awards subject to service and/or performance vesting conditions, the grant date fair value is established based on the closing price of the Company's common stock on such date. Stock-based compensation expense for awards subject to only service conditions is recognized on a straight-line basis over the service period. Stock-based compensation expense for awards subject to both service and performance conditions are recognized on a graded basis if it is probable that the performance condition will be achieved. The Company accounts for forfeitures of awards granted under these plans as they occur in determining stock-based compensation expense.

For awards subject to a market condition, the grant date fair value is estimated using a Monte Carlo valuation model. The Company recognizes stock-based compensation expense for awards subject to market-based vesting conditions regardless of whether the market conditions are achieved or not, and stock-based compensation expense for any such awards is reversed only when the implied service requirement is not met. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

Service-Based RSAs

The following table reflects the outstanding service-based RSAs and activity related thereto for the three months ended March 31, 2025:

	Service-based Awards	
	Number of Shares	**Weighted-average Grant Date Fair Value**
Outstanding at December 31, 2024	457,376	$ 35.36
Shares granted	139,175	27.91
Shares forfeited	(1,313)	34.88
Shares vested	(126,323)	32.09
Outstanding at March 31, 2025	468,915	$ 28.38

At March 31, 2025, there was $13.9 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 1.28 years. For the three months ended March 31, 2025 and 2024, the total fair value of the Company's restricted stock awards vested was $3.3 million and $5.8 million, respectively. For the three months ended March 31, 2025, the compensation expenses associated with these awards were $2.0 million.

Performance Equity Awards

The following table reflects the outstanding RSUs that are subject to market conditions linked to TSR ("TSR Awards") and activity related thereto for the three months ended March 31, 2025:

	TSR Awards	
	Number of Units	**Weighted-average Grant Date Fair Value**
Outstanding at December 31, 2024	287,990	$ 38.87
Units granted	—	—
Units forfeited	—	—
Units vested	—	—
Outstanding at March 31, 2025	287,990	$ 38.87

For the three months ended March 31, 2025, the compensation expenses associated with these awards were $1.2 million. As of March 31, 2025, the unrecognized compensation expenses for these awards were $6.9 million, which will be amortized over the remaining performance period.

In December 2023, the Company also granted performance equity awards, in the form of SARs. The final payout (if any) will be a dollar amount, which may be settled in cash, shares or a combination of both at the Company's option. The Company plans to settle the SARs Awards that were granted in 2023 with shares. For the three months ended March 31, 2025, the compensation expenses associated with these awards were $0.4 million. As of March 31, 2025, the unrecognized compensation expenses for these awards were $4.1 million, which will be amortized over the remaining performance period.

The Company used Monte Carlo simulation models, described above, to estimate (i) the fair value of the TSR Awards that were granted in 2023 and 2024 based on the expected outcome of the Company's absolute TSR as well as TSR relative to the defined peer group and (ii) the fair value of the SARs Awards that were granted in 2023 based on the expected outcome of the Company's market capitalization appreciation rate. The Company used the following key assumptions in its Monte Carlo simulation models: (a) risk-free rates ranging from 1.7% to 4.2%, (b) dividend yield ranging from nil to 4.3%, and (c) expected volatility ranging from 56.4% to 72.3%.

Warrants

In January 2022, as partial consideration for the purchase of certain oil and natural gas properties, the Company issued warrants to purchase 1,939,998 shares of the Company's common stock at an exercise price equal to $28.30 per share (subject to certain anti-dilution adjustments) (the "Warrants").

In March 2023, the Company issued 403,780 shares of common stock in exchange for the surrender and cancellation of a portion of the Warrants. Immediately prior to their cancellation, such Warrants that were surrendered were exercisable for an aggregate of approximately 824,602 shares of common stock at an exercise price of $27.4946 per share. Neither the Company nor the holders paid any cash consideration in the transaction.

In March 2024, the Company issued 656,297 shares of common stock in exchange for the surrender and cancellation of all of the remaining Warrants. Immediately prior to their cancellation, such Warrants that were surrendered were exercisable for an aggregate of approximately 1,223,963 shares of common stock at an exercise price of $26.3324 per share. Neither the Company nor the holders paid any cash consideration in the transaction.

There were no outstanding warrants or activity related thereto for the three months ended March 31, 2025.

NOTE 7 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the Company's financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

Joint Development Agreement

In December 2024, the Company entered into a Joint Development Agreement ("JDA") with an operator to jointly develop certain natural gas and NGL properties in the Appalachian Basin. Pursuant to the JDA, the Company is required to participate in and fund a share of total development capital expenses for wells spud during calendar year 2025. As of March 31, 2025, the Company's total remaining capital commitment for wells spud in the remainder of calendar year 2025 is expected to not exceed $140.0 million for a 15% working interest.

NOTE 8 INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three months ended March 31, 2025 and 2024 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income primarily due to the non-deductibility of permanent items, state income taxes, and discrete items during the three months ended March 31, 2025 and 2024.

In assessing the realizability of deferred tax assets ("DTAs"), management considers whether it is more likely than not that some portion, or all, of the Company's DTAs will not be realized. In making such determination, the Company considers all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the projected future income and results of operations, and (iv) its ability to use tax planning strategies. If the Company concludes that it is more likely than not that some portion, or all, of its DTAs will not be realized, the tax asset is reduced by a valuation allowance. The Company assesses the appropriateness of its valuation allowance on a quarterly basis.

The Company had an income tax expense of approximately $46.8 million and $2.8 million for the three months ended March 31, 2025 and 2024, respectively. The effective tax rates for the three months ended March 31, 2025 and 2024 were 25.2% and 19.7%, respectively.

NOTE 9 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2025 and December 31, 2024:

	Fair Value Measurements at March 31, 2025 Using		
(In thousands)	**Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Commodity Derivatives – Current Assets	$ —	$ 143,841	$ —
Commodity Derivatives – Noncurrent Assets	—	65,871	—
Commodity Derivatives – Current Liabilities	—	(118,912)	—
Commodity Derivatives – Noncurrent Liabilities	—	(138,528)	—
Interest Rate Derivatives – Current Assets	—	119	—
Total	$ —	$ (47,609)	$ —

(In thousands)	Fair Value Measurements at December 31, 2024 Using Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Assets	$ —	$ 46,365	$ —
Commodity Derivatives – Noncurrent Assets	—	9,729	—
Commodity Derivatives – Current Liabilities	—	(19,915)	—
Commodity Derivatives – Noncurrent Liabilities	—	(93,606)	—
Interest Rate Derivatives - Current Assets	—	160	—
Interest Rate Derivatives – Noncurrent Assets	—	103	—
Total	$ —	$ (57,164)	$ —

Commodity Derivatives. The Level 2 instruments presented in the tables above include commodity derivative instruments (see Note 10). The fair value of the Company's commodity derivative instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of commodity derivative contracts is reflected in the balance sheets. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Interest Rate Derivatives. The Level 2 instruments presented in the tables above include interest rate derivative instruments (see Note 10). The fair value of the Company's interest rate derivative instruments is determined based upon contracted notional amounts, active market-quoted interest yield curves, and time to maturity, among other things. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of interest rate derivative contracts is reflected in the condensed balance sheets. The current interest rate derivative asset balances represent the fair values expected to be settled in the subsequent twelve months.

Fair Value of Other Financial Instruments

The carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Long-term debt is not presented at fair value in the balance sheets, as it is recorded at carrying value, net of unamortized debt issuance costs and unamortized premium (see Note 4). The fair value of the Company's Senior Notes due 2028, Convertible Notes due 2029 and Senior Notes due 2031 was $708.6 million, $528.2 million and $512.5 million, respectively, at March 31, 2025. These fair values are based on market quotes that represent Level 2 inputs.

There is no active market for the Revolving Credit Facility. The recorded value of the Revolving Credit Facility approximates its fair value because of its floating rate structure based on the SOFR spread, secured interest, and the Company's borrowing base utilization. The fair value measurement for the Revolving Credit Facility represents Level 2 inputs.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the relevant accounting standards. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred and acquired during the three months ended March 31, 2025 and 2024 were approximately $0.9 million and $1.1 million, respectively.

The Company issued common stock warrants in January 2022 as a part of the purchase consideration for certain oil and natural gas properties acquired by the Company. Upon issuance, the Warrants granted holders the right to purchase 1,939,998 shares of the Company's common stock at an exercise price equal to $28.30 per share (subject to certain adjustments), generally exercisable from April 27, 2022 until January 27, 2029. A portion of the Warrants were surrendered and cancelled in March 2023, and the remaining Warrants were surrendered and cancelled in March 2024, in each case in exchange for shares of common stock. See Note 6. The fair value of the Warrants consideration was determined by utilizing an Option Pricing Model. These non-recurring fair value measurements are primarily determined using inputs that are observable or can be corroborated by observable market data (Level 2 inputs).

For all transactions accounted for as business combinations, the Company uses the acquisition method of accounting. In those instances, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the three months ended March 31, 2025.

NOTE 10 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes various commodity price derivative instruments to (i) reduce the effects of volatility in price changes on the crude oil and natural gas commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending. In addition, from time to time the Company utilizes interest rate swaps to mitigate exposure to changes in interest rates on the Company's variable-rate indebtedness.

All derivative instruments are recorded in the Company's condensed balance sheets as either assets or liabilities measured at their fair value (see Note 9). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the Company's condensed statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivative instruments that have not been settled. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The Company has master netting agreements on individual derivative instruments with certain counterparties and therefore the current asset and liability are netted in the balance sheet and the non-current asset and liability are netted in the balance sheet for contracts with these counterparties.

Commodity Derivative Instruments

The following table presents settlements on commodity derivative instruments and unsettled gains and losses on open commodity derivative instruments for the periods presented which is recorded in the revenue section of our condensed statements of operations:

	Three Months Ended March 31,	
(In thousands)	**2025**	**2024**
Cash Received on Settled Derivatives	$ 12,062	$ 19,117
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	9,699	(157,648)
Gain (Loss) on Commodity Derivatives, Net	$ 21,761	$ (138,531)

The following table summarizes open commodity derivative positions as of March 31, 2025, for commodity derivatives that were entered into through March 31, 2025, for the settlement periods presented**:**

	2025	2026	2027	2028
Oil:				
NYMEX WTI - Swaps:				
Volume (Bbl)	8,291,463	1,564,557	—	—
Weighted-Average Price ($/Bbl)	$ 73.71	$ 70.90	$ —	$ —
NYMEX WTI - Swaptions[1]:				
Volume (Bbl)	10,360,075	5,887,550	915,000	—
Weighted-Average Price ($/Bbl)	$ 73.92	$ 71.27	$ 61.75	$ —
Argus WTI Midland - Basis Swaps:				
Volume (Bbl)	8,213,262	4,723,291	—	—
Weighted-Average Price ($/Bbl)	$ 0.96	$ 1.05	$ —	$ —
NYMEX WTI - Call Options[1]:				
Volume (Bbl)	3,274,700	2,701,365	4,015,000	1,921,500
Weighted-Average Price ($/Bbl)	$ 80.36	$ 73.18	$ 79.59	$ 70.14
Brent ICE - Call Options [1]:				
Volume (Bbl)	—	—	—	316,590
Weighted-Average Price ($/Bbl)	$ —	$ —	$ —	$ 80.00
NYMEX WTI - Collars:				
Collar Put Volume (Bbl)	5,628,690	4,301,842	—	—
Collar Call Volume (Bbl)	7,086,176	6,051,557	—	—
Weighted-Average Floor Price ($/Bbl)	$ 69.24	$ 65.58	$ —	$ —
Weighted-Average Ceiling Price ($/Bbl)	$ 77.48	$ 74.72	$ —	$ —
Natural Gas:				
NYMEX Henry Hub - Swaps:				
Volume (MMBtu)	23,389,353	14,700,000	—	—
Weighted-Average Price ($/MMBtu)	$ 4.10	$ 4.07	$ —	$ —
Waha Gas Daily - Swaps:				
Volume (MMBtu)	1,375,000	1,825,000	155,000	—
Weighted Average Price ($/MMBtu)	$ 3.20	$ 3.20	$ 3.20	$ —
NYMEX Henry Hub - Swaptions [1]:				
Volume (MMBtu)	24,660,000	23,845,000	23,790,000	—
Weighted-Average Price ($/MMBtu)	$ 4.15	$ 4.06	$ 3.98	$ —
Waha - Basis Swaps:				
Volume (MMBtu)	17,088,000	18,250,000	3,650,000	—
Weighted-Average Price ($/MMBtu)	$ (0.88)	$ (0.84)	$ (0.78)	$ —
Waha Index Swaps				
Volume (MMBtu)	17,305,000	18,560,000	4,890,000	
Weighted Average Price ($/MMBtu)	$ —	$ —	$ 0.01	
TETCO M2 - Basis Swaps:				
Volume (MMBtu)	15,125,000	16,735,000	620,000	—
Weighted-Average Price ($/MMBtu)	$ (1.02)	$ (0.98)	$ (0.99)	$ —
TCO - Basis Swaps:				
Volume (MMBtu)	1,375,000	—	—	—

Weighted-Average Price ($/MMBtu)	$ (0.87)	$ —	$ —	$ —
NYMEX Henry Hub - Call Options [1]:				
Volume (MMBtu)	8,954,750	3,239,500	35,523,000	6,700,000
Weighted-Average Price ($/MMBtu)	$ 3.73	$ 6.00	$ 5.97	$ 4.50
NYMEX Henry Hub - Collars:				
Collar Put Volume (MMBtu)	29,313,236	32,357,303	5,010,000	—
Collar Call Volume (MMBtu)	29,313,236	32,357,303	5,010,000	—
Weighted-Average Floor Price ($/MMBtu)	$ 3.14	$ 3.33	$ 3.00	$ —
Weighted-Average Ceiling Price ($/MMBtu)	$ 4.83	$ 4.97	$ 3.86	$ —
NGL:				
TET-OPIS - Swaps:				
Volume (Bbl)	101,150	376,275	234,800	—
Weighted-Average Price ($/Bbl)	$ 36.65	$ 33.90	$ 31.19	$ —

(1) Swaptions are crude oil and natural gas derivative contracts that give counterparties the option to extend certain derivative contracts for additional periods. Call Options are crude oil and natural gas derivative contracts sold by the Company that give counterparties the option to exercise certain derivative contracts. The volumes and prices reflected as Swaptions and Call Options in this table will only be effective if the options are exercised by the applicable counterparties.

Interest Rate Derivative Instruments

At times, the Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. The settlement of derivative instruments is recognized as a component of interest expense in the statements of operations. The mark-to-market component of these derivative instruments is recognized in gain (loss) on unsettled interest rate derivatives, net in the statements of operations. The following table summarizes our open interest rate derivative contracts as of March 31, 2025.

Fixed Rate Swap Agreements

	Swaps		
Contract Period	**Notional Amount**	**Fixed Rate**	**Floating Benchmark**
October 1, 2024 - October 1, 2026	$ 25,000,000	3.423 %	USD-SOFR CME

Other Information Regarding Derivative Instruments

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at March 31, 2025 and December 31, 2024, respectively. Certain amounts may be presented on a net basis in the condensed financial statements when such amounts are with the same counterparty and subject to a master netting arrangement.

(In thousands)

Type of Commodity	Balance Sheet Location	March 31, 2025 Estimated Fair Value	December 31, 2024 Estimated Fair Value
Derivative Assets:			
Commodity Price Swap Contracts	Current Assets	$ 47,602	$ 49,031
Commodity Basis Swap Contracts	Current Assets	49,678	21,419
Commodity Price Swaptions Contracts	Current Assets	2,391	5,398
Commodity Price Collar Contracts	Current Assets	37,748	46,839
Commodity Price Call Option Contracts	Current Assets	6,422	2,289
Interest Rate Swap Contracts	Current Assets	119	160
Commodity Price Swap Contracts	Noncurrent Assets	7,601	8,710
Commodity Basis Swap Contracts	Noncurrent Assets	28,139	16,513
Commodity Price Swaptions Contracts	Noncurrent Assets	1,016	—
Commodity Price Collar Contracts	Noncurrent Assets	29,115	35,652
Interest Rate Swap Contracts	Noncurrent Assets	—	103
Total Derivative Assets		$ 209,831	$ 186,114
Derivative Liabilities:			
Commodity Price Swap Contracts	Current Liabilities	$ (16,455)	$ (3,667)
Commodity Basis Swap Contracts	Current Liabilities	(2,753)	(5,150)
Commodity Price Swaptions Contracts	Current Liabilities	(852)	(44,174)
Commodity Price Collar Contracts	Current Liabilities	(41,233)	(29,668)
Commodity Price Call Option Contracts	Current Liabilities	(57,619)	(15,867)
Commodity Price Swap Contracts	Noncurrent Liabilities	(5,192)	(3,852)
Commodity Basis Swap Contracts	Noncurrent Liabilities	(1,281)	(2,564)
Commodity Price Swaptions Contracts	Noncurrent Liabilities	(387)	(44,315)
Commodity Price Collar Contracts	Noncurrent Liabilities	(30,551)	(36,327)
Commodity Price Call Option Contracts	Noncurrent Liabilities	(101,117)	(57,693)
Total Derivative Liabilities		$ (257,440)	$ (243,278)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted in the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected in the balance sheets. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

(In thousands)	Estimated Fair Value at March 31, 2025		
	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 143,960	$ (91,056)	$ 52,904
Non-Current Assets	65,871	$ (64,621)	1,250
Total Derivative Assets	$ 209,831	$ (155,677)	$ 54,154
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (118,911)	$ 91,056	$ (27,855)
Non-Current Liabilities	(138,529)	64,621	(73,908)
Total Derivative Liabilities	$ (257,440)	$ 155,677	$ (101,763)

(In thousands)	Estimated Fair Value at December 31, 2024		
	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 125,137	$ (78,612)	$ 46,525
Non-Current Assets	60,977	$ (51,145)	9,832
Total Derivative Assets	$ 186,114	$ (129,757)	$ 56,357
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (98,527)	$ 78,612	$ (19,915)
Non-Current Liabilities	(144,751)	51,145	(93,606)
Total Derivative Liabilities	$ (243,278)	$ 129,757	$ (113,521)

All of the Company’s outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (“ISDAs”) entered into with parties that are also lenders under the Company’s Revolving Credit Facility. The Company’s obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of March 31, 2025. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 9 for the aggregate fair value of all derivative instruments that were in a net liability position at March 31, 2025 and December 31, 2024.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

Cautionary Statement Concerning Forward-Looking Statements

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our Revolving Credit Facility, our intention or ability to pay or increase dividends on our capital stock, and impairment are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production, sales, market size, collaborations, cash flows, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following:

- changes in crude oil and natural gas prices, the pace of drilling and completions activity on our current properties and properties pending acquisition;
- infrastructure constraints and related factors affecting our properties;
- general economic or industry conditions, whether internationally, nationally and/or in the communities in which our company conducts business, including any future economic downturn, cost inflation, supply chain disruptions, the impact of continued or further inflation, disruption in the financial markets, changes in the interest rate environment and actions taken by OPEC and other oil producing countries as it pertains to the global supply and demand of, and prices for, crude oil, natural gas and NGLs;
- ongoing legal disputes over, and potential shutdown of, the Dakota Access Pipeline;
- our ability to identify and consummate additional development opportunities and potential or pending acquisition transactions, the projected capital efficiency savings and other operating efficiencies and synergies resulting from our acquisition transactions, integration and benefits of property acquisitions, or the effects of such acquisitions on our company's cash position and levels of indebtedness;
- changes in our reserves estimates or the value thereof;
- disruption to our company's business due to acquisitions and other significant transactions;
- changes in local, state, and federal laws, regulations or policies that may affect our business or our industry (such as the effects of tax law changes, and changes in environmental, health, and safety regulation and regulations addressing climate change, and trade policy and tariffs);
- conditions of the securities markets;
- risks associated with our Convertible Notes, including the potential impact that the Convertible Notes may have on our financial position and liquidity, potential dilution, and that provisions of the Convertible Notes could delay or prevent a beneficial takeover of our company;
- the potential impact of the capped call transactions undertaken in tandem with the Convertible Notes issuance, including counterparty risk;
- increasing attention to environmental, social and governance matters;
- our ability to raise or access capital on acceptable terms;
- cyber-incidents could have a material adverse effect on our business, financial condition or results of operations;
- changes in accounting principles, policies or guidelines;
- events beyond our control, including a global or domestic health crisis, acts of terrorism, political or economic instability or armed conflict in oil and gas producing regions; and
- other economic, competitive, governmental, regulatory and technical factors affecting our operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2024, as updated by subsequent reports we file with the SEC (including this report), which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Overview

Our primary strategy is to invest in non-operated minority working and mineral interests in oil and natural gas properties, with a core area of focus in the premier basins within the United States. Using this strategy, we had participated in 11,097 gross (1,133.9 net) producing wells as of March 31, 2025. As of March 31, 2025, we had leased approximately 291,672 net acres, of which approximately 85% were developed and all were located in the United States.

We have grown and diversified our business significantly over the last several years through acquisitions of oil and natural gas properties. See Note 3 to our condensed financial statements for information regarding our recent acquisition activities.

Our average daily production in the first quarter of 2025 was approximately 134,959 Boe per day, of which approximately 58% was oil. This was a 13% increase in production compared to the first quarter of 2024, primarily due to production attributable to recent acquisitions and new wells added to production. During the three months ended March 31, 2025, we added 27.3 net wells to production.

Our weighted average percentage of production volumes by basin for the three months ended March 31, 2025 and 2024 were as follows:

	Three Months Ended March 31, 2025				
	Williston	Permian	Appalachian	Uinta	Total
Oil (Bbl)	41 %	48 %	— %	11 %	100 %
Natural Gas (Mcf)	24 %	41 %	33 %	2 %	100 %
Total (Boe)	34 %	45 %	14 %	7 %	100 %

	Three Months Ended March 31, 2024				
	Williston	Permian	Appalachian	Uinta	Total
Oil (Bbl)	49 %	51 %	— %	— %	100 %
Natural Gas (Mcf)	29 %	37 %	34 %	— %	100 %
Total (Boe)	41 %	45 %	14 %	— %	100 %

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

- *Commodity price differentials*. The price differential between our well head price for oil and the NYMEX WTI benchmark price is primarily driven by the cost to transport oil via train, pipeline or truck to refineries, as well as certain other immaterial non-cash revenue adjustments. The price differential between our well head price for natural gas and

NGLs and the NYMEX Henry Hub benchmark price is primarily driven by gathering and transportation costs, as well as certain other immaterial non-cash revenue adjustments.

- *Gain (loss) on commodity derivatives, net.* We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (i) cash gains and losses we recognize on settled commodity derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period end.

- *Production expenses.* Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

- *Production taxes.* Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- *Depreciation, depletion, amortization and accretion.* Depreciation, depletion, amortization and accretion includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method. Accretion expense relates to the passage of time of our asset retirement obligations.

- *General and administrative expenses.* General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

- *Interest expense.* We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our unproved cost pool. We include interest expense that is not capitalized into the unproved cost pool, the amortization of deferred financing costs and bond premiums (including origination and amendment fees), commitment fees and annual agency fees as interest expense. Further, we record the settled amounts of our interest rate derivative instruments as interest expense.

- *Impairment expense.* Under the full cost method of accounting, the Company is required to perform a ceiling test impairment review each quarter. The test determines a limit, or ceiling, on the book value of the Company's oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The Company did not have any ceiling test impairment for the three months ended March 31, 2025 and 2024. Average commodity prices have declined in recent months. If this downward trend continues, and/or if our proved reserves decrease significantly in future months, the present value of the Company's future net revenues could decline significantly, which could trigger the need for the Company to record a non-cash ceiling test impairment of its oil and gas property costs in future periods.

- *Income tax expense.* Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;

- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in commodity prices;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of substantially all of our acreage and wells in the Williston, Permian, Appalachian and Uinta Basins subjects our operating results to factors specific to these operating regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or more of these operating regions.

The price at which our oil production is sold typically reflects a discount to the NYMEX WTI benchmark price. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX Henry Hub benchmark price. Thus, our operating results are also affected by changes in the price differentials between the applicable benchmark prices and the sales prices we receive for our production. Our average oil price differential to the NYMEX WTI benchmark price during the three months ended March 31, 2025 was $5.79 per barrel, as compared to $3.99 per barrel in the three months ended March 31, 2024. The increase in our average oil price differential year-over-year was due primarily to the addition of the Uinta Basin to our portfolio of oil and natural gas assets, pursuant to the XCL Acquisition, as described in Note 3 to the Company's condensed financial statements. Our net average realized gas price in the three months ended March 31, 2025 was $3.86 per Mcf, representing 100% realization relative to the average NYMEX Henry Hub pricing. In comparison, our net average realized gas price was $2.47 per Mcf in the three months ended March 31, 2024, which represented a 118% realization relative to the average NYMEX Henry Hub pricing. Fluctuations in our oil and natural gas price realizations are due to several factors such as realized pricing by basin, gathering and transportation costs, transportation methods, takeaway capacity relative to production levels, regional storage capacity, seasonal refinery maintenance temporarily depressing demand, and in the case of gas realizations, the price of NGLs.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. Generally, higher commodity prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower commodity prices have generally had the opposite effect. In addition, individual components of drilling costs can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the type and amount of proppant used. In recent years, we have observed inflationary pressures on drilling and other operating costs due to various factors, such as higher commodity prices, labor shortages, supply chain disruptions and other macroeconomic factors. During the three months ended March 31, 2025 and 2024, the weighted average gross authorization for expenditure (or AFE) cost for wells we elected to participate in was $10.5 million and $9.5 million, respectively.

Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially production from properties within the United States, the production quota set by OPEC, and the strength of the U.S. dollar can significantly impact oil prices. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

During the first quarter of 2025 and continuing into April 2025, a decline in oil prices occurred as a result of, among other things, (i) uncertainties regarding U.S. trade policies and tariffs driving concerns over increasing inflation, (ii) continued concerns over slowing global economic growth and resulting reductions in estimated global oil consumption, and (iii) the decision by OPEC to increase production starting in May 2025, creating additional global supply and further downward pressure on oil prices. These factors led to declining oil prices, with the NYMEX price for oil reaching $59.58 on April 8, 2025, the lowest level since the second quarter of 2021.

Although U.S. inflation rates were relatively stable during the first quarter of 2025, they remain slightly higher than historical averages. Inflationary pressures, such as trade tariffs, can lead to economic slowdown and/or lead to a recession, which in turn can cause a decrease in short-term or longer-term demand for commodities, resulting in oversupply and potential for lower commodity prices.

The foregoing destabilizing factors have caused dramatic fluctuations in global financial markets and uncertainty about world-wide oil and natural gas supply and demand, which in turn has increased the volatility of oil and natural gas prices. Prolonged lower oil prices and inflationary costs could impact our operating partners' development schedule for the non-operated wells in which we have a working interest and. Additionally, such prolonged depressed prices could result in a significant triggering event indicating impairment over our oil and natural gas assets. Any of the foregoing events or circumstances could impact our future sales volume, operating revenues and expenses, liquidity, per unit metrics and capital expenditures.

In light of current macroeconomic uncertainty and geopolitical tensions, including developments pertaining to Russia's invasion of Ukraine, conflicts in the Middle East and potential further imposition of domestic and foreign tariffs, we cannot predict any future volatility in or levels of commodity prices or demand for oil and natural gas.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the three months ended March 31, 2025 and 2024.

	Three Months Ended March 31,	
	2025	2024
Average NYMEX Prices[(1)]		
Natural Gas (per MMbtu)	$ 3.87	$ 2.10
Oil (per Bbl)	$ 71.42	$ 76.91

(1) Based on average NYMEX closing prices.

We have entered into derivatives contracts to hedge commodity price risk on a portion of our future expected oil and natural gas production. For a summary as of March 31, 2025, of our open commodity price derivative contracts for future periods, see "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" in Part I, Item 3 below. See also Note 10 to our condensed financial statements.

Results of Operations for the Three Months Ended March 31, 2025 and March 31, 2024

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Three Months Ended March 31,		
	2025	2024	% Change
Net Production:			
Oil (MBbl)	7,081	6,386	11 %
Natural Gas (MMcf)	30,394	26,893	13 %
Total (MBoe)	12,146	10,869	12 %
Net Sales (in thousands):			
Oil Sales	$ 459,682	$ 465,679	(1)%
Natural Gas and NGL Sales	117,270	66,362	77 %
Gain on Settled Commodity Derivatives	12,062	19,117	(37)%
Gain (Loss) on Unsettled Commodity Derivatives	9,699	(157,648)	
Other Revenue	3,385	2,838	19 %
Total Revenues	602,098	396,348	52 %
Average Sales Prices:			
Oil (per Bbl)	$ 64.92	$ 72.92	(11)%
Effect of Gain (Loss) on Settled Oil Derivatives on Average Price (per Bbl)	1.55	(0.84)	
Oil Net of Settled Oil Derivatives (per Bbl)	66.47	72.08	(8)%
Natural Gas and NGLs (per Mcf)	$ 3.86	$ 2.47	56 %
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.04	0.91	(96)%
Natural Gas and NGLs Net of Settled Natural Gas and NGL Derivatives (per Mcf)	3.90	3.38	15 %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	$ 47.50	$ 48.95	(3)%
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	0.99	1.76	(44)%
Realized Price on a Boe Basis Including Settled Commodity Derivatives	48.49	50.71	(4)%
Operating Expenses (in thousands):			
Production Expenses	$ 114,040	$ 105,447	8 %
Production Taxes	36,069	$ 51,210	(30)%
General and Administrative Expenses	14,481	$ 11,393	27 %
Depletion, Depreciation, Amortization and Accretion	205,690	$ 173,958	18 %
Other Expense	2,537	2,019	26 %
Costs and Expenses (per Boe):			
Production Expenses	$ 9.39	$ 9.70	(3)%
Production Taxes	2.97	4.71	(37)%
General and Administrative Expenses	1.19	1.05	13 %
Depletion, Depreciation, Amortization and Accretion	16.93	16.01	6 %
Net Producing Wells at Period End	1,133.9	985.3	15 %

Oil and Natural Gas Sales

In the first quarter of 2025, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, was $577.0 million, compared to $532.0 million in the first quarter of 2024. The increase was driven by a 12% increase in production volumes, partially offset by a 3% decrease in realized prices.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas production from existing wells. Acquisitions were a significant driver of our 12% increase in production levels in the first quarter of 2025 compared to the same period of 2024.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our net result from commodity derivatives trade was a gain of $21.8 million in the first quarter of 2025, compared to a loss of $138.5 million in the first quarter of 2024. Net gain or loss on commodity derivatives is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For the first quarter of 2025, we realized a gain on settled commodity derivatives of $12.1 million, compared to a gain of $19.1 million in the first quarter of 2024. For the first quarter of 2025, we realized a gain on our unsettled commodity derivative of $9.7 million, compared to a loss of $157.6 million in the first quarter of 2024.

Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At March 31, 2025, all of our unsettled derivative contracts are recorded at their fair values, which was a net liability of $47.6 million, a change of $9.6 million from the $57.2 million net liability recorded as of December 31, 2024. The decrease in net liability at March 31, 2025 as compared to December 31, 2024 was primarily due to changes in forward commodity prices relative to prices on our open commodity derivative contracts since December 31, 2024. Our open commodity derivative contracts are summarized in "Item 3. Quantitative and Qualitative Disclosures about Market Risk —Commodity Price Risk."

Production Expenses

Production expenses were $114.0 million in the first quarter of 2025, compared to $105.4 million in the first quarter of 2024. On a per unit basis, production expenses were $9.39 per Boe in the first quarter of 2025 compared to $9.70 per Boe in the first quarter of 2024. The increase in our production expenses in the first quarter of 2025 compared to the first quarter of 2024 was primarily due to a 12% increase in production volumes and a 15% increase in the total number of net producing wells.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $36.1 million in the first quarter of 2025, compared to $51.2 million in the first quarter of 2024. As a percentage of oil and natural gas sales, our production taxes were 6.3% and 9.6% in the first quarter of 2025 and 2024, respectively. The fluctuation in our production taxes and average production tax rates year-over-year was primarily due to a higher proportion of our 2025 production coming from the Permian basin, which has a relatively lower average production tax rate.

General and Administrative Expenses

General and administrative expenses were $14.5 million in the first quarter of 2025, or $1.19 per Boe, compared to $11.4 million in the first quarter of 2024, or $1.05 per Boe. The increase was primarily driven by a higher personnel headcount as well as the timing of share-based compensation and professional fees.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $205.7 million in the first quarter of 2025, compared to $174.0 million in the first quarter of 2024. Depletion expense, the largest component of DD&A, increased by $31.6 million in the first quarter of 2025 compared to the first quarter of 2024, primarily due to a 12% increase in production volumes year-over-year. On a per unit basis, depletion expense was $16.84 per Boe in the first quarter of 2025 compared to $15.91 per Boe in the first quarter of 2024. The higher depletion rate per Boe was primarily driven by a higher depletable cost base as the result of the closing of several larger acquisitions in 2024. Depreciation, amortization and accretion was $1.1 million and $1.0 million in the first quarter of 2025 and 2024, respectively. The following table summarizes DD&A expense per Boe for the first quarter of 2025 and 2024:

	Three Months Ended March 31,			
	2025	2024	$ Change	% Change
Depletion	$ 16.84	$ 15.91	$ 0.93	6 %
Depreciation, Amortization and Accretion	0.09	0.10	(0.01)	(10)%
Total DD&A Expense	$ 16.93	$ 16.01	$ 0.92	6 %

Interest Expense

Interest expense, net of capitalized interest, was $43.9 million in the first quarter of 2025 compared to $37.9 million in the first quarter of 2024. The increase was primarily due to higher levels of debt pursuant to borrowings to fund the Company's recent acquisition activities.

Income Tax

During the first quarter of 2025, we recorded income tax expense of $46.8 million, as compared to $2.8 million recorded for the first quarter of 2024. The higher income tax expense in the first quarter of 2025 was driven by a higher taxable income as compared to the same period in 2024.

Liquidity and Capital Resources

Overview

Our main sources of liquidity and capital resources as of the date of this report have been internally generated cash flow from operations, proceeds from equity and debt financings, credit facility borrowings and cash settlements of commodity derivative instruments. Our primary uses of capital have been for the acquisition, development and operation of our oil and natural gas properties, cash settlements of commodity derivative instruments and for stockholder returns. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

During the three months ended March 31, 2025, we repurchased and retired 499,100 shares of our common stock for total consideration of $15.0 million (excluding brokerage commissions and excise taxes), or an average price of $30.07 per share.

As of March 31, 2025, we had outstanding total debt of $2,335.1 million consisting of $630.0 million of borrowings under our Revolving Credit Facility, $705.1 million aggregate principal amount of our Senior Notes due 2028, $500.0 million aggregate principal amount of our Convertible Notes due 2029, and $500.0 million aggregate principal amount of our Senior Notes due 2031.

As of March 31, 2025, we had total liquidity of $0.9 billion, consisting of $0.9 billion of committed borrowing availability under the Revolving Credit Facility and $33.6 million of cash on hand.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 80% and 88% of our total oil and gas sales in the first quarter of 2025 and 2024, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas and NGL prices. We seek to maintain a robust hedging program to mitigate volatility in commodity prices with respect to a portion of our expected production. For the three months ended March 31, 2025, we hedged approximately 68% of our crude oil production and approximately 62% of our natural gas production. For a summary as of March 31, 2025, of our open commodity swap contracts for future periods, see “Quantitative and Qualitative Disclosures about Market Risk” in Part I, Item 3 below.

With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months and, based on current expectations, for the foreseeable future. However, we may seek additional access to capital and liquidity. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

Our recent capital commitments have been to fund acquisitions and development of oil and natural gas properties. We expect to fund our near-term capital requirements and working capital needs with cash flows from operations and available borrowing capacity under our Revolving Credit Facility. Our capital expenditures could be curtailed if our cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

Working Capital

Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, collection of receivables, expenditures related to our development and production operations and the impact of our outstanding derivative instruments.

At March 31, 2025, we had a working capital deficit of $42.7 million, compared to a deficit of $43.5 million at December 31, 2024. Current assets increased by $20.9 million and current liabilities increased by $20.0 million at March 31, 2025, compared to December 31, 2024.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. We typically enter into commodity derivative transactions covering a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 36 months. See “Quantitative and Qualitative Disclosures about Market Risk” in Part I, Item 3 below.

Our cash summary flows for the three months ended March 31, 2025 and 2024 are presented below:

	Three Months Ended March 31,	
(In thousands, unaudited)	**2025**	**2024**
Net Cash Provided by Operating Activities	$ 407,426	$ 392,147
Net Cash Used for Investing Activities	(264,558)	(407,056)
Net Cash Provided by (Used for) Financing Activities	(118,225)	39,183
Net Increase in Cash	$ 24,643	$ 24,273

Cash Flows from Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2025 was $407.4 million, compared to $392.1 million in the same period of the prior year. This increase was primarily due to higher oil and gas sales driven by higher production volumes. Net cash provided by operating activities is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital and other items (as reflected in our statements of cash flows) in the three months ended March 31, 2025 was a surplus of $20.0 million compared to a surplus of $39.7 million in the same period of the prior year.

Cash Flows from Investing Activities

Cash flows used in investing activities during the three months ended March 31, 2025 and 2024 were $264.6 million and $407.1 million, respectively. Cash used in investing activities was higher during the three months ended March 31, 2024 because of the Delaware Acquisition, as described in Note 3 to the Company's condensed financial statements.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity. For instance, during the three months ended March 31, 2025, our capitalized costs incurred, excluding non-cash consideration, for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $259.7 million, while the actual cash spend in this regard amounted to $264.0 million.

Development and acquisition activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns. Our cash spend for development and acquisition activities for the three months ended March 31, 2025 and 2024 are summarized in the following table:

	Three Months Ended March 31,	
(In thousands, unaudited)	**2025**	**2024**
Drilling and Development Capital Expenditures	$ 237.8	$ 272.2
Acquisition of Oil and Natural Gas Properties	25.2	134.0
Other Capital Expenditures	1.0	0.8
Total	$ 264.0	$ 407.0

Cash Flows from Financing Activities

Net cash used for financing activities was $118.2 million during the three months ended March 31, 2025, compared to net cash provided by financing activities of $39.2 million during the three months ended March 31, 2024.

For the three months ended March 31, 2025, cash used for financing activities was primarily due to $115.0 million repayment of borrowings under our Revolving Credit Facility, $41.7 million of common stock dividend payments, and $15.0 million in repurchases of common stock, partially offset by $55.0 million of net advances under our Revolving Credit Facility.

For the three months ended March 31, 2024, cash provided by financing activities was primarily due to $180.0 million borrowing under our Revolving Credit Facility, partially offset by $78.0 million repayment under our Revolving Credit Facility, $40.1 million payment for common stock dividends, and $20.0 million in repurchases of common stock.

Revolving Credit Facility

We have entered into a Revolving Credit Facility with Wells Fargo Bank, as administrative agent, and the lenders from time to time party thereto. The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to our oil and natural gas properties. As of March 31, 2025, the Revolving Credit Facility had a borrowing base of $1.8 billion and an elected commitment amount of $1.5 billion, and we had $630.0 million in borrowings outstanding under the facility, leaving $0.9 billion in available committed borrowing capacity. See Note 4 to our condensed financial statements for further details regarding the Revolving Credit Facility.

Senior Notes due 2028

As of March 31, 2025, we had outstanding $705.1 million aggregate principal amount of our Senior Notes due 2028. See Note 4 to our condensed financial statements for further details regarding the Senior Notes due 2028.

Senior Notes due 2031

As of March 31, 2025, we had outstanding $500.0 million aggregate principal amount of our Senior Notes due 2031. See Note 4 to our condensed financial statements for further details regarding the Senior Notes due 2031.

Convertible Notes due 2029

As of March 31, 2025, we had outstanding $500.0 million aggregate principal amount of our Convertible Notes. See Note 4 to our condensed financial statements for further details regarding the Convertible Notes.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Based on current conditions and expectations, we are not presently budgeting for any material change in per well drilling and completion and other associated costs in 2025 compared to 2024.

Contractual Obligations and Commitments

Please see our disclosure of contractual obligations and commitments as of December 31, 2024, included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2024.

Critical Accounting Estimates

Critical accounting estimates are those estimates made in accordance with GAAP that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on our financial condition or results of operations. Our critical accounting estimates include impairment testing of natural gas and crude oil production properties, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting estimates from those reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2024.

A description of our critical accounting policies, including estimates, was provided in Note 2 to our financial statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2024.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2024 and, except as set forth below, have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to commodity price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

The following table summarizes our open crude oil derivative contracts as of March 31, 2025, by fiscal quarter.

Crude Oil Contracts

	Swaps[1]		Collars			
Contract Period	Volume (Bbls)	Weighted Average Price ($/Bbl)	Volume Ceiling (Bbls)	Volume Floor (Bbls)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Floor Price ($/Bbl)
2025(1)						
Q2	2,877,658	$ 74.41	2,502,671	2,019,233	$ 77.45	$ 69.41
Q3	2,613,969	73.51	2,304,994	1,817,970	77.43	69.15
Q4	2,799,836	73.17	2,278,511	1,791,487	77.55	69.15
2026(1)						
Q1	758,726	$ 71.60	2,000,726	1,569,289	$ 75.37	$ 64.58
Q2	266,657	70.31	1,340,457	904,227	74.41	66.15
Q3	269,587	70.24	1,355,187	914,163	74.41	66.15
Q4	269,587	70.15	1,355,187	914,163	74.41	66.15

(1) This table does not include volumes subject to swaptions and call options, which are crude oil derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. This table also does not include basis swaps. See Note 10 to our condensed financial statements for further details regarding our commodity derivatives, including the swaptions and call options that are not included in the foregoing table.

The following table summarizes our open natural gas derivative contracts as of March 31, 2025, by fiscal quarter.

Natural Gas Contracts

	Swaps[1]		Collars			
Contract Period	Volume (MMBTU)	Weighted Average Price ($/MMBTU)	Volume Ceiling (MMBTU)	Volume Floor (MMBTU)	Weighted Average Ceiling Price ($/MMBTU)	Weighted Average Floor Price ($/MMBTU)
2025[1]						
Q2	8,266,664	$ 3.94	9,859,633	9,859,633	$ 4.82	$ 3.12
Q3	8,549,432	4.06	9,828,137	9,828,137	4.81	3.12
Q4	7,948,257	4.16	9,625,466	9,625,466	4.87	3.19
2026[1]						
Q1	5,045,000	$ 4.10	8,498,249	8,498,249	$ 4.99	$ 3.34
Q2	4,445,000	3.85	8,784,706	8,784,706	4.99	3.34
Q3	4,140,000	3.95	8,784,706	8,784,706	4.99	3.34
Q4	2,895,000	3.97	6,289,642	6,289,642	4.91	3.31
2027[1]						
Q1	155,000	$ 3.20	1,335,000	1,335,000	$ 3.86	$ 3.00
Q2	—	—	1,380,000	1,380,000	3.86	3.00
Q3	—	—	1,380,000	1,380,000	3.86	3.00
Q4	—	—	915,000	915,000	3.86	3.00

(1) This table does not include volumes subject to swaptions and call options, which are natural gas derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. This table also does not include basis swaps. See Note 10 to our condensed financial statements for further details regarding our commodity derivatives, including the call options and basis swaps that are not included in the foregoing table.

The following table summarizes our open NGL derivative contracts as of March 31, 2025, by fiscal quarter.

NGL Contracts

Contract Period	Swaps Volume (BBL)	Swaps Weighted Average Price ($/BBL)
2025:		
Q2	4,550	$ 37.03
Q3	29,900	36.39
Q4	66,700	36.75
2026:		
Q1	92,250	$ 36.00
Q2	106,925	33.32
Q3	96,600	33.03
Q4	80,500	33.32
2027:		
Q1	65,250	$ 32.30
Q2	59,150	30.73
Q3	57,500	30.69
Q4	52,900	30.87

Interest Rate Risk

Our long-term debt as of March 31, 2025 was comprised of borrowings that contain fixed and floating interest rates. Our Senior Notes due 2028, Senior Notes due 2031, and Convertible Notes bear cash interest at fixed rates. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement (see Note 4 to our condensed financial statements).

From time to time, the Company may use interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. The following table summarizes our open interest rate derivative contracts as of March 31, 2025.

Fixed Rate Swap Agreements (in thousands)

Contract Period	Swaps Notional Amount	Swaps Fixed Rate	Swaps Floating Benchmark
October 1, 2024 - October 1, 2026	$ 25,000	3.423 %	USD-SOFR CME

Changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at March 31, 2025 would cost us approximately $6.3 million in additional annual interest expense.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934, as amended ("Exchange Act"), reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

As of March 31, 2025, our management, including our principal executive officer and principal financial officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our principal executive officer and principal financial officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of March 31, 2025.

Changes in Internal Control over Financial Reporting

No change in our Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended March 31, 2025, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. ***Legal Proceedings.***

Our Company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 1A. ***Risk Factors.***

There have been no material changes to the risk factors disclosed in the "Risk Factors" section of our Annual Report on Form 10-K filed with the SEC for the period ended December 31, 2024.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds.***

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) of our common stock during the quarter ended March 31, 2025.

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 Value of Shares that May Yet be Purchased Under the Plans or Programs (at period end)[2]
Month #1				
January 1, 2025 to January 31, 2025	—	$ —	—	$ 110.3 million
Month #2				
February 1, 2025 to February 28, 2025	155,646	$ 32.13	155,646	105.3 million
Month #3				
March 1, 2024 to March 9, 2025	179,336	$ 27.90	179,336	100.3 million
March 10, 2024 to March 31, 2025	214,498 [1]	$ 30.22	164,118	195.3 million
Total	549,480	$ 30.00	499,100	195.3 million

(1) Includes 50,380 shares surrendered by employees in satisfaction of tax withholding obligations in connection with the vesting of restricted stock awards.

(2) On July 23, 2024, the Company's board of directors approved and promptly announced a stock repurchase program to acquire up to $150 million of the Company's outstanding common stock. On March 10, 2025, the Company's board of directors approved and promptly announced an additional $100 million authorization under this stock repurchase program. The program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

Item 3. ***Defaults Upon Senior Securities.***

None.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

Item 5. ***Other Information.***

(a) None.

(b) None.

(c) During the quarter ended March 31, 2025, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K, except as follows:

- On March 3, 2025, Nicholas O’Grady (CEO) terminated his previously-disclosed Rule 10b5-1 trading arrangement that was adopted on May 24, 2024.

Item 6. ***Exhibits.***

Exhibit No.	Description	Reference
3.1	Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated August 24, 2018	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
3.2	Certificate of Amendment to the Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated September 18, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 24, 2020
3.3	Certificate of Amendment of Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated May 23, 2024	Incorporated by reference to Exhibit 3.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on July 31, 2024
3.4	Amended and Restated Bylaws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 20, 2023
31.1	Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
101.INS	Inline XBRL Instance Document	Filed herewith
101.SCH	Inline XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith
104	The cover page from Northern Oil and Gas, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2025, formatted in Inline XBRL and contained in Exhibit 101	Filed herewith

SIGNATURES

Pursuant to the requirements 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.

NORTHERN OIL AND GAS, INC.

Date:	April 30, 2025	By:	/s/ Nicholas O'Grady
			Nicholas O'Grady, Chief Executive Officer (on behalf of Registrant)
Date:	April 30, 2025	By:	/s/ Chad Allen
			Chad Allen, Chief Financial Officer and principal financial and accounting officer (on behalf of Registrant)

Exhibit 31.1

CERTIFICATION

I, Nicholas O'Grady certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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; and

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: April 30, 2025

By: /s/ Nicholas O'Grady

Nicholas O'Grady
Principal Executive Officer

Exhibit 31.2

CERTIFICATION

I, Chad Allen certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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; and

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting;

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: April 30, 2025

By: /s/ Chad Allen

Chad Allen
Principal Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Northern Oil and Gas, Inc., (the "Company") on Form 10-Q for the quarterly period ended March 31, 2025, as filed with the United States Securities and Exchange Commission on the date hereof, (the "Report"), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: April 30, 2025	By: /s/ Nicholas O'Grady
	Nicholas O'Grady Principal Executive Officer
Dated: April 30, 2025	By: /s/ Chad Allen
	Chad Allen Principal Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.