Viper Energy, Inc.

2024 Annual Report

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

FORM 10-K

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

For the fiscal year ended December 31, 2024
OR

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

Commission File Number 001-36505

Viper Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

DE	**46-5001985**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas **Suite 100** **Midland, TX**	**79701**
(Address of principal executive offices)	**(Zip code)**

(Registrant's telephone number, including area code): (432) 221-7400

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, $0.000001 Par Value	VNOM	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

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

None.

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

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

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

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

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

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

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

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2024 was approximately $3.4 billion.

As of February 21, 2025, 131,313,142 shares of Class A Common Stock and 87,831,750 shares of Class B Common Stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Viper Energy, Inc.'s Proxy Statement for the 2025 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

VIPER ENERGY, INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2024

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms used in this Annual Report on Form 10-K (the "Annual Report" or this "report"):

Argus WTI Midland	Grade of oil that serves as a benchmark price for oil at Midland, Texas.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl or barrel	One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BO	One barrel of crude oil.
BO/d	One barrel of crude oil per day.
BOE	One barrel of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of crude oil equivalent per day.
British Thermal Unit or BTU	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Condensate	Liquid hydrocarbons associated with the production that is primarily natural gas.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Deterministic method	The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.
Developed acreage	Acreage allocated or assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Development well	A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
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.
Exploitation	A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Finding costs	Capital costs incurred in the acquisition of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Fracturing	The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a mineral interest is owned.
Henry Hub	Natural gas gathering point that serves as a benchmark price for natural gas futures on the NYMEX.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBbls	One thousand barrels of crude oil and other liquid hydrocarbons.
MBO	One thousand barrels of crude oil.
MBO/d	One thousand barrels of crude oil per day.

MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
MBOE/d	One thousand BOE per day.
Mcf	One thousand cubic feet of natural gas.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	One million British Thermal Units.
MMcf	Million cubic feet of natural gas.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty, overriding interests and other burdens.
Net royalty acres	Net mineral acres multiplied by the average lease royalty interest and other burdens.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play or Resource play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment	Refers to the sealing off of fluids in the reservoir penetrated by a well so that the fluids from one reservoir will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD	Proved undeveloped reserves.
Productive well	A well that is found to be mechanically capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercially recoverable hydrocarbons.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion	The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
Reserves	Reserves are estimated remaining quantities of oil and natural 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 natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or crude oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development, which may be subject to expiration.
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.
Spud	Commencement of actual drilling operations.

Standardized measure	The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.
Tight formation	A formation with low permeability that produces natural gas with very low flow rates for long periods of time.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Waha Hub	Natural gas gathering point that serves as a benchmark price for natural gas at western Texas and New Mexico.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI	West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil that serves as a benchmark for oil on the NYMEX.
WTI Cushing	Grade of oil that serves as a benchmark price for oil at Cushing, Oklahoma.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms used in this report:

Adjusted EBITDA	Consolidated Adjusted EBITDA, a non-GAAP measure, generally equals net income (loss) attributable to Viper Energy, Inc. plus net income (loss) attributable to non-controlling interest before interest expense, net, non-cash share-based compensation expense, depletion, non-cash (gain) loss on derivative instruments, other non-cash operating expenses, other non-recurring expenses and provision for (benefit from) income taxes, which measure is used by management to more effectively evaluate the operating performance and determine dividend amounts for purposes of the dividend policy.
ASU	Accounting Standards Update.
Class A Common Stock	Class A Common Stock, $0.000001 par value per share, of Viper Energy, Inc.
Class B Common Stock	Class B Common Stock, $0.000001 par value per share, of Viper Energy, Inc.
Common Stock	Collectively, Class A Common Stock and Class B Common Stock.
Conversion	The transaction, effective November 13, 2023, whereby the Partnership converted from a Delaware limited partnership to a Delaware corporation known as “Viper Energy, Inc.”
Diamondback	Diamondback Energy, Inc., a Delaware corporation.
Diamondback E&P LLC	A subsidiary of Diamondback.
EPA	U.S. Environmental Protection Agency.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company; the general partner of the Partnership and a wholly owned subsidiary of Diamondback prior to the Conversion.
LTIP	Viper Energy, Inc. Amended and Restated 2014 Long Term Incentive Plan, as amended and restated by Viper Energy, Inc. 2024 Amended and Restated Long Term Incentive Plan, and as may be further amended or restated from time to time.
Nasdaq	The Nasdaq Global Select Market.
Notes	The outstanding senior notes of Viper Energy, Inc. issued under indentures where Viper Energy Partners, LLC is the sole guarantor, consisting of the 5.375% Senior Notes due 2027 and the 7.375% Senior Notes due 2031.
NYMEX	New York Mercantile Exchange.
OPEC	Organization of the Petroleum Exporting Countries.
Operating Company or OpCo	Viper Energy Partners LLC, a Delaware limited liability company and a consolidated subsidiary of Viper Energy, Inc.
OpCo Units	Units representing limited liability company interests in the Operating Company having the rights and interests with respect to “Units” specified in the Operating Company’s Third Amended and Restated Limited Liability Company Agreement dated as of October 1, 2024, as it may be further amended, restated or otherwise modified from time to time.
Partnership	Viper Energy Partners LP, the predecessor of the Company, which converted into the Company in the Conversion.
Partnership Agreement	The second amended and restated agreement of limited partnership of the Partnership, dated as of May 9, 2018, as amended as of May 10, 2018 and further amended on November 2, 2023.
Ryder Scott	Ryder Scott Company, L.P.
S&P 500	Standard and Poor’s 500 index.
SEC	United States Securities and Exchange Commission.
SEC Prices	Unweighted arithmetic average oil and natural gas prices as of the first day of the month for the most recent 12 months as of the balance sheet date.
Securities Act	The Securities Act of 1933, as amended.
SOFR	The secured overnight financing rate.
Wells Fargo	Wells Fargo Bank, National Association.
XOP	Standard and Poor’s Oil and Gas Exploration and Production industry index.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act, which involve risks, uncertainties, and assumptions. All statements, other than statements of historical fact, including statements regarding our: future performance; business strategy; future operations; estimates and projections of operating income, losses, costs and expenses, returns, cash flow, and financial position; production levels on properties in which we have mineral and royalty interests, developmental activity by other operators; reserve estimates and our ability to replace or increase reserves; anticipated benefits or other effects of strategic transactions; and plans and objectives of management (including Diamondback's plans for developing our acreage and our cash dividend policy and repurchases of our Class A Common Stock and/or Notes) are forward-looking statements. When used in this report, the words "aim," "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "future," "guidance," "intend," "may," "model," "outlook," "plan," "positioned," "potential," "predict," "project," "seek," "should," "target," "will," "would," and similar expressions (including the negative of such terms) as they relate to us are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Although we believe that the expectations and assumptions reflected in our forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond our control. Accordingly, forward-looking statements are not guarantees of our future performance and the actual outcomes could differ materially from what we expressed in our forward-looking statements.

Factors that could cause the outcomes to differ materially include (but are not limited to) the following:

- changes in supply and demand levels for oil, natural gas, and natural gas liquids and the resulting impact on the price for those commodities;
- the impact of public health crises, including epidemic or pandemic diseases and any related company or government policies or actions;
- actions taken by the members of OPEC and Russia affecting the production and pricing of oil, as well as other domestic and global political, economic, or diplomatic developments;
- changes in general economic, business or industry conditions, including changes in foreign currency exchange rates, interest rates, inflation rates, or instability in the financial sector;
- regional supply and demand factors, including delays, curtailment delays or interruptions of production on our mineral and royalty acreage, or governmental orders, rules or regulations that impose production limits on such acreage;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations;
- physical and transition risks relating to climate change;
- restrictions on the use of water, including limits on the use of produced water by our operators and a moratorium on new produced water well permits recently imposed by the Texas Railroad Commission in an effort to control induced seismicity in the Permian Basin;
- significant declines in prices for oil, natural gas, or natural gas liquids, which could require recognition of significant impairment charges;
- changes in U.S. energy, environmental, monetary and trade policies;
- conditions in the capital, financial and credit markets, including the availability and pricing of capital for drilling and development by our operators and environmental and social responsibility projects undertaken by Diamondback and our other operators;
- changes in availability or cost of rigs, equipment, raw materials, supplies and oilfield services impacting our operators;
- changes in safety, health, environmental, tax, and other regulations or requirements impacting us or our operators (including those addressing air emissions, water management, or the impact of global climate change);
- security threats, including cybersecurity threats and disruptions to our business from breaches of Diamondback's information technology systems, or from breaches of information technology systems of our operators or third parties with whom we transact business;
- lack of, or disruption in, access to adequate and reliable transportation, processing, storage and other facilities impacting our operators;
- severe weather conditions and natural disasters;

- acts of war or terrorist acts and the governmental or military response thereto;
- changes in the financial strength of counterparties to the credit facility and hedging contracts of our operating subsidiary;
- changes in our credit rating;
- failure to consummate the Pending 2025 Drop Down acquisition discussed in this report or realize anticipated benefits from the Pending 2025 Drop Down or our recent acquisitions; and
- other risks and factors disclosed in this report.

In light of these factors, the events anticipated by our forward-looking statements may not occur at the time anticipated or at all. Moreover, new risks emerge from time to time. We cannot predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those anticipated by any forward-looking statements we may make. Accordingly, you should not place undue reliance on any forward-looking statements made in this report. All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by applicable law.

PART I

On November 13, 2023, Viper Energy Partners LP (the "Partnership") converted from a Delaware limited partnership to a Delaware corporation (the "Conversion") named "Viper Energy, Inc." References in this Annual Report to "Viper," "the Company," "our company," "we," "our," "us" or like terms refer to (i) Viper Energy, Inc. and collectively with its subsidiary Viper Energy Partners LLC, as the context requires, following the Conversion, and (ii) Viper Energy Partners LP individually and collectively with its subsidiary, Viper Energy Partners LLC, as the context requires, prior to the Conversion. References in this Annual Report to (i) the "Operating Company" or "OpCo" refers to Viper Energy Partners LLC, and (ii) "Diamondback" refers collectively to Diamondback Energy, Inc. and its subsidiaries other than the Company. References in this Annual Report to shares or per share amounts prior to the Conversion refer to common units and Class B units or per unit amounts. Unless otherwise noted, all references to shares or per share amounts following the Conversion refer to shares or per share amounts of Class A Common Stock and Class B Common Stock. All references to dividends prior to the Conversion refer to distributions. See Note 1—Organization and Basis of Presentation in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of the Conversion.

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Overview

We are a publicly traded Delaware corporation focused on owning and acquiring mineral and royalty interests in oil and natural gas properties primarily in the Permian Basin. We operate in one reportable segment. Effective November 13, 2023, we converted our legal status from a Delaware limited partnership into a Delaware corporation. Our primary business objective is to provide an attractive return to our stockholders by focusing on business results, generating robust free cash flow, reducing debt and protecting our balance sheet, while maintaining what we believe is a best-in-class cost structure. Our assets consist of mineral and royalty interests in oil and natural gas properties primarily in the Permian Basin in West Texas, substantially all of which are leased to working interest owners who bear the costs of operation and development.

We are currently focused primarily on oil and natural gas properties primarily in the Permian Basin, which is one of the oldest and most prolific producing basins in North America. The Permian Basin, which consists of approximately 75,000 square miles centered around Midland, Texas, has been a significant source of oil production since the 1920s. The Permian Basin is known to have a number of zones of oil and natural gas bearing rock throughout.

Significant Recent Acquisitions and Divestitures and Pending 2025 Drop Down

Morita Ranches Acquisition

On February 14, 2025, we completed an acquisition of certain mineral and royalty interests located in Howard County, Texas from Morita Ranches Minerals, LLC ("Morita Ranches") (the "Morita Ranches Acquisition"), pursuant to a definitive purchase and sale agreement for consideration consisting of approximately (i) $211.0 million in cash and (ii) 2.40 million OpCo Units together with an equal number of shares of our Class B Common Stock issued to certain affiliate designees of Morita Ranches (the "Morita Ranches Equity Recipients"), subject to certain transaction costs and post-closing adjustments. The mineral and royalty interests included in the Morita Ranches Acquisition represent approximately 1,691 net royalty acres in the Permian Basin, 75% of which are operated by Diamondback, and have an average net royalty interest of approximately 8.6% and current production of approximately 768 BO/d.

Pending 2025 Drop Down Transaction

On January 30, 2025, we and the Operating Company, as buyer parties, entered into a definitive equity purchase agreement with Endeavor Energy Resources, LP ("Endeavor"), 1979 Royalties, LP and 1979 Royalties GP, LLC (collectively, the "Endeavor Subsidiaries"), each of which is a subsidiary of Diamondback, to acquire the Endeavor Subsidiaries from Endeavor for consideration consisting of (i) $1.0 billion in cash and (ii) the issuance of 69.63 million OpCo Units and an equal number of shares of our Class B Common Stock (collectively, the "Equity Issuance"), in each case subject to customary closing adjustments, including, among other things, for net title benefits (such transaction, the "Pending 2025 Drop Down").

The mineral and royalty interests owned by the Endeavor Subsidiaries and to be acquired in the Pending 2025 Drop Down represent approximately 22,847 net royalty acres in the Permian Basin, 69% of which are operated by Diamondback, and have an average net royalty interest of approximately 2.8% and current oil production of approximately 17,097 BO/d (the "Endeavor Mineral and Royalty Interests"). The Endeavor Mineral and Royalty Interests include interests in horizontal wells comprised of 6,055 gross proved developed production wells (of which approximately 29% are operated by Diamondback), 116 gross completed wells and 394 gross drilled but uncompleted wells, all of which are principally concentrated in the Midland Basin, with the balance located primarily in the Delaware and Williston Basins.

The completion of the Pending 2025 Drop Down is subject to a number of conditions to closing as specified in the equity purchase agreement for the Pending 2025 Drop Down. These closing conditions include, among others, (i) the approval of the Pending 2025 Drop Down by (a) the holders of a majority of the voting power of our Common Stock entitled to vote on such proposal, voting together as a single class, at a special meeting of our stockholders, excluding the shares beneficially owned by Diamondback and its subsidiaries, and (b) the holders of a majority of our outstanding Common Stock, in each case as required by Delaware law, (ii) the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act (the "HSR Act") relating to the Pending 2025 Drop Down, and (iii) the satisfaction or waiver of other customary closing conditions. Additionally, the Equity Issuance is subject to the approval by our stockholders representing a majority of the total votes cast at the special meeting on such proposal, as required by the rules of the Nasdaq Stock Market LLC. We expect to hold the special meeting of our stockholders and, subject to the satisfaction or waiver of the foregoing conditions, close the Pending 2025 Drop Down during the second quarter of 2025.

After giving effect to our recently completed 2025 Equity Offering and the Morita Ranches Acquisition discussed in this report, we currently estimate that following the closing of the Pending 2025 Drop Down, Diamondback will beneficially own approximately 52% of our outstanding Common Stock, on a fully diluted basis.

See Note 13—Subsequent Events in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of the Morita Ranches Acquisition and the Pending 2025 Drop Down, as well as Item 1A. Risk Factors for discussion of risks relating to the Pending 2025 Drop Down.

Tumbleweed Acquisitions

In September and October of 2024, we completed a series of related acquisitions including the TWR Acquisition, the Q Acquisition and the M Acquisition, collectively the ("Tumbleweed Acquisitions") as defined and discussed below.

On October 1, 2024, we acquired all of the issued and outstanding equity interests in TWR IV, LLC and TWR IV SellCo, LLC from Tumbleweed Royalty IV, LLC ("TWR IV") and TWR IV SellCo Parent, LLC (the "TWR Acquisition"), pursuant to a definitive purchase and sale agreement for consideration consisting of approximately (i) $464.2 million in cash, including transaction costs and certain customary post-closing adjustments, (ii) 10.09 million OpCo Units to TWR IV, (iii) an option (the "TWR Class B Option") granted to TWR IV to acquire up to 10.09 million shares of our Class B Common Stock, and (iv) contingent cash consideration of up to $41.0 million, payable in January of 2026, based on the average price of WTI sweet crude oil prompt month futures contracts for the calendar year 2025, (the "WTI 2025 Average"). The mineral and royalty interests acquired in the TWR Acquisition represent approximately 3,067 net royalty acres located primarily in the Permian Basin.

On September 3, 2024, we acquired all of the issued and outstanding equity interests in (i) Tumbleweed-Q Royalties, LLC (the "Q Acquisition") for a purchase price of approximately $114.0 million in cash, including transaction costs and certain customary post-closing adjustments, and contingent cash consideration of up to $5.4 million, payable in January of 2026, based on the WTI 2025 Average, and (ii) MC TWR Royalties, LP and MC TWR Intermediate, LLC (the "M Acquisition") for a purchase price of approximately $76.1 million in cash, including transaction costs and certain customary post-closing adjustments, and contingent cash consideration of up to $3.6 million, payable in January of 2026, based on the WTI 2025 Average (together, the "Q and M Acquisitions"). The mineral and royalty interests acquired in the Q and M Acquisitions represent approximately 673 net royalty acres located primarily in the Permian Basin.

Other Acquisitions

During the year ended December 31, 2024, the Company acquired, in individually insignificant transactions from unrelated third-party sellers, mineral and royalty interests representing 261 net royalty acres in the Permian Basin for an aggregate purchase price of approximately $54.2 million, including customary closing adjustments.

Divestiture

In the second quarter of 2024, we divested all of our non-Permian assets for a purchase price of approximately $87.2 million, including transaction costs and customary post-closing adjustments. The divested properties consisted of approximately 2,713 net royalty acres with current production of approximately 450 BO/d.

See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for further information.

Our Properties

As of December 31, 2024, our assets consisted of mineral interests and royalty interests underlying 987,861 gross acres and 35,671 net royalty acres primarily in the Permian Basin, and Diamondback was the operator of approximately 52% of our net royalty acreage. As of December 31, 2024, there were 14,707 gross productive wells on this acreage, 3,714 of which were operated by Diamondback. Net production during the fourth quarter of 2024 was approximately 56,109 BOE/d and net production for the year ended December 31, 2024 averaged 49,784 BOE/d. For the years ended December 31, 2024, 2023 and 2022, royalty income generated from these mineral and royalty interests was $853.6 million, $717.1 million and $838.0 million, respectively.

At December 31, 2024, our estimated proved oil and natural gas reserves totaled 195,873 MBOE based on reserve estimates prepared by our internal reservoir engineers and audited by Ryder Scott, an independent petroleum engineering firm. As of December 31, 2024, approximately 84% of our proved reserves were classified as proved developed producing reserves. Proved undeveloped, or PUD, reserves included in this estimate were from 837 gross horizontal well locations. As of December 31, 2024, our proved reserves were approximately 48% oil, 27% natural gas liquids and 25% natural gas.

Our Relationship with Diamondback

As of December 31, 2024, Diamondback beneficially owned all of our 85,431,453 shares of outstanding Class B Common Stock, representing approximately 45% of the then outstanding voting power of our capital stock. We believe Diamondback's significant ownership in us may motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so and may elect to dispose of mineral and other interests in such properties without offering us the opportunities to acquire them.

We believe Diamondback views our company as part of its business strategy and that Diamondback may be incentivized to pursue additional acquisitions jointly with us in the future. However, Diamondback will regularly evaluate acquisitions and may elect to acquire properties without offering us the opportunity to participate in such transactions. Moreover, Diamondback may not be successful in identifying potential acquisitions. Diamondback is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to present us with acquisition or disposition opportunities.

In addition, neither we nor our Operating Company have any employees. Diamondback provides management, operating and administrative services to us under the services and secondment agreement, including the services of the executive officers and other employees, in a similar manner as Diamondback provided to the General Partner pre-Conversion. Please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes in Item 8. Financial Statements and Supplementary Data of this report.

Business Strategies

Our primary business objective is to generate the highest value proposition for our stockholders through a focus on increasing long-term per share growth and returns by generating robust free cash flow, reducing debt and protecting our balance sheet. We intend to accomplish this objective by executing the following strategies:

- ***Capitalize on the development of the properties underlying our mineral interests to grow our cash flow***. We expect the production from our mineral interests will increase as Diamondback and our other operators continue to drill, complete and develop our acreage. We expect to capitalize on this development, which requires no capital expenditure funding from us, and believe the anticipated increase in our aggregate royalty payment receipts will enable us to grow our cash flows.

- ***Leverage our relationship with Diamondback to participate with it in acquisitions of mineral or other interests in producing properties from third parties and to increase the size and scope of our potential third-party acquisition targets***. We have in the past and intend to continue to make opportunistic acquisitions of mineral and other interests that have substantial oil-weighted resource potential and organic growth potential. Through our relationships with Diamondback and its affiliates, we have access to their significant pool of management talent and industry relationships, which we believe provide us with a competitive advantage in pursuing potential third-party acquisition opportunities. For example, we and Diamondback may pursue an acquisition where Diamondback acquires working and revenue interests in properties and we acquire mineral or royalty interests in such properties either in the same or subsequent transactions.

- ***Seek to acquire from Diamondback, from time to time, mineral or other interests in producing oil and natural gas properties that meet our acquisition criteria***. Since our formation, we have acquired, and may have additional opportunities from time to time in the future to acquire, mineral or other interests in producing oil and natural gas properties directly from Diamondback, including the Endeavor Mineral and Royalty Interests subject to the Pending 2025 Drop Down. We believe Diamondback may continue to be incentivized to sell properties to us, as doing so may enhance Diamondback's economic returns by monetizing long-lived producing properties while potentially retaining a portion of the resulting cash flow through dividends on Diamondback's controlling interests in us. However, neither Diamondback nor any of its affiliates are contractually obligated to offer or sell any interests in properties to us.

- ***High-grade our asset base.*** We intend to continue to high-grade our asset base and selectively divest non-core minerals with limited optionality when the amount negotiated exceeds our projected total value and then redeploy proceeds into our core areas of focus.

- ***Maintain a conservative capital structure to allow financial flexibility.*** Since our formation, we have maintained a conservative capital structure that has allowed us to opportunistically purchase accretive mineral and other interests. We are committed to maintaining a conservative leverage profile, and will continue to seek to opportunistically fund accretive acquisitions. In addition to returning capital to our stockholders through base and variable dividends in accordance with our dividend policy and share repurchases under our stock repurchase program, we intend to continue to repay debt using free cash flow to ensure our ability to successfully operate in challenging business and commodity price environments.

- ***Hedge to manage commodity price risk and to protect our balance sheet and cash flow***. We use a combination of derivative instruments to economically hedge exposure to changes in commodity prices and maintain financial and balance sheet flexibility.

Competitive Strengths

We believe the following competitive strengths will allow us to successfully execute our business strategies and achieve our primary business objective:

- ***Oil rich resource base in one of North America's leading resource plays***. As of December 31, 2024, 295 horizontal drilling rigs were operating in the Permian Basin, representing 51% of the total U.S. onshore horizontal rig activity. The majority of our mineral and royalty acreage is well positioned in the core of both the Midland and Delaware Basins in the Permian Basin. Production on our mineral and royalty acreage for the year ended December 31, 2024 and our estimated net proved reserves are heavily oil-weighted.

- ***Sustainable, high margin business unburdened by capital expenses with minimal operating expenses.*** Our mineral and royalty interests provide us cash flows without the requirement to fund drilling and completion costs or lease operating expenses. Our operating costs consist of certain royalty taxes, gathering, processing, marketing and transportation costs and general and administrative expenses, providing us with a low cost structure and high operating margins that generate increasing free cash flow growth in a stable or rising price environment as the underlying production associated with our royalty interests continues to grow.

- ***Experienced and proven management team***. Diamondback provides us with personnel and general and administrative services, including the services of the executive officers, senior management and other employees, pursuant to the services and secondment agreement entered into in connection with the Conversion. The members of our executive team have significant industry experience, most of which has been focused on resource play development primarily in the Permian Basin, and Diamondback, which currently operates approximately 52% of our mineral and royalty acreage, has a proven track record of executing on multi-rig development drilling programs and extensive experience primarily in the Permian Basin. In addition, our executive team has significant experience with acquisition of properties and businesses in the oil and natural gas industry. We expect to benefit from the industry relationships of the management team. We believe the experience of our management team is essential for the execution of our business strategy.

- ***Favorable and stable business environment.*** We primarily focus our growth in the Permian Basin, one of the oldest, most prolific hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. We believe that the geological and regulatory environment is more stable and predictable, and that we are faced with fewer operational risks in the Permian Basin as compared to emerging hydrocarbon basins. We believe that the impact of the proven application of new technology, combined with the substantial geological information available about the Permian Basin, also reduces the risk of development and exploration activities on our mineral and royalty acreage as compared to emerging hydrocarbon basins.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

The estimated reserves as of December 31, 2024, 2023 and 2022 are based on reserve estimates prepared by our internal reservoir engineers and audited by Ryder Scott, an independent petroleum engineering firm. The internal and external technical persons responsible for preparing or auditing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis. The purpose of Ryder Scott’s audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates for 2024, 2023 and 2022. The proved reserve audits performed by Ryder Scott for 2024, 2023 and 2022 covered 100% of our total proved reserves for each respective year. A copy of the summary audit report prepared by Ryder Scott is included as Exhibit 99.1 to this Annual Report.

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible–from a given date forward, from known reservoirs 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2024 were estimated using a deterministic method.

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (i) performance-based methods, (ii) volumetric-based methods, and (iii) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. In general, our proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods included, but were not limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. In certain cases where there was inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate, the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, we considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

The process of estimating oil, natural gas and natural gas liquids reserves is complex and requires significant judgment, as discussed in Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates of this report. As a result, our petroleum engineers and geoscience professionals have an internal controls process to ensure the integrity, accuracy and timeliness of the data used to calculate proved reserves relating to our assets primarily in the Permian Basin. Our internal technical staff met with our independent reserve auditors periodically during their audit of the period covered by the reserve report to discuss the assumptions and methods used in our proved reserve estimation process. As part of the audit process, we provide historical information to the independent reserve auditors for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Diamondback's Executive Vice President and Chief Engineer is primarily responsible for overseeing the preparation of all of our reserve estimates and overseeing communications with our independent reserve auditor. Diamondback's Executive Vice President and Chief Engineer is a petroleum engineer with over 21 years of reservoir and operations experience and our geoscience staff has an average of approximately 16 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs used to estimate economic lives of our properties. Ryder Scott performed an independent analysis during its audit of our estimated reserves for 2024 and any differences were reviewed with Diamondback's Executive Vice President and Chief Engineer. For 2024, our reserve auditor's estimates of our proved reserves did not differ materially from our estimates by more than the established audit tolerance guidelines of ten percent.

The internal control procedures utilized in the preparation of our proved reserve estimates are intended to ensure reliability of reserve estimations, and include, but are not limited to the following:

- review and verification of historical production data, which is based on actual production as reported by our operators;
- preparation of reserve estimates by the primary reserve engineers or under their direct supervision;
- review by the primary reserve engineers of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- review of historical realized commodity prices and differentials from index prices compared to the differentials used in the reserves database;
- direct reporting responsibilities by Diamondback's Executive Vice President and Chief Engineer to our Chief Executive Officer and by the current primary reserve engineer to our President;
- prior to finalizing the reserve report, a review of our preliminary proved reserve estimates by Diamondback's President and Chief Financial Officer, Diamondback's Executive Vice President and Chief Operating Officer, Diamondback's Executive Vice President and Chief Engineer and our primary reserves engineers takes place on an annual basis;
- review of our proved reserve estimates by our Audit Committee with our executive team and Ryder Scott on an annual basis;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

For estimates and further discussion of our proved developed and proved undeveloped reserves, see Note 15—Supplemental Information on Oil and Natural Gas Operations in Item 8. Financial Statements and Supplementary Data of this report.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

Our properties are located primarily in the Midland and Delaware Basins of the Permian Basin in Texas. At December 31, 2024, 2023 and 2022, the Midland Basin and the Delaware Basin each contained 15% or more of our total proved reserves.

The following table sets forth information regarding our share of our operators' net production of oil, natural gas and natural gas liquids for these fields along with our share of our operators' net production from fields containing less than 15% of our total proved reserves:

	Midland	Delaware	Other	Total
Production Data:				
Year Ended December 31, 2024				
Oil (MBbls)	7,105	2,766	68	9,939
Natural gas (MMcf)	16,802	7,482	322	24,606
Natural gas liquids (MBbls)	2,976	1,174	31	4,181
Combined volumes (MBOE)(1)	12,881	5,187	153	18,221
Year Ended December 31, 2023				
Oil (MBbls)	5,789	2,210	29	8,028
Natural gas (MMcf)	13,088	5,984	58	19,130
Natural gas liquids (MBbls)	2,323	782	3	3,108
Combined volumes (MBOE)(1)	10,293	3,989	42	14,324
Year Ended December 31, 2022				
Oil (MBbls)	5,219	1,765	113	7,097
Natural gas (MMcf)	10,648	4,864	356	15,868
Natural gas liquids (MBbls)	1,859	617	64	2,540
Combined volumes (MBOE)(1)	8,853	3,193	236	12,282

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per one Bbl.

The following table sets forth certain average sales price information for each of the periods indicated:

	Year Ended December 31,		
	2024	2023	2022
Average Sales Prices:			
Oil ($/Bbl)	$ 75.48	$ 77.13	$ 94.02
Natural gas ($/Mcf)	$ 0.60	$ 1.62	$ 5.24
Natural gas liquids ($/Bbl)	$ 21.17	$ 21.55	$ 34.47
Combined ($/BOE)	$ 46.85	$ 50.06	$ 68.23
Oil, hedged ($/Bbl)(1)	$ 74.57	$ 76.05	$ 92.85
Natural gas, hedged ($/Mcf)(1)	$ 0.85	$ 1.37	$ 4.20
Natural gas liquids ($/Bbl)(1)	$ 21.17	$ 21.55	$ 34.47
Combined price, hedged ($/BOE)(1)	$ 46.68	$ 49.13	$ 66.21

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include realized gains and losses on cash settlements for matured commodity derivatives, which we do not designate for hedge accounting.

Productive Wells

As of December 31, 2024, we owned an average 2.7% net revenue interest in 14,707 gross productive wells, including an average 2.7% net revenue interest in 14,076 gross oil productive wells and an average 1.4% net revenue interest in 631 gross natural gas productive wells. As of December 31, 2024, we had 18 gross wells with an average 3.7% net revenue interest in process of being drilled by Diamondback. The expected timing of our wells is based primarily on permitting by third-party operators or Diamondback's current expected completion schedule. Productive wells consist of producing wells capable of production, including natural gas awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest.

Acreage

The following table sets forth information as of December 31, 2024 relating to the gross and net royalty acreage of our mineral interests:

Basin	Gross Royalty Acreage	Net Royalty Acreage
Delaware	381,325	14,712
Midland	606,536	20,959
Total acreage	987,861	35,671

Our net interest in production from our mineral interests is based on lease royalty terms which vary from property to property. Our interest in the majority of these properties is perpetual in nature, however an insignificant portion of our net royalty acreage consists of overriding royalty interests which may be subject to expiration. Net royalty acres are defined as net mineral acres multiplied by the average lease royalty interest and other burdens.

Title to Properties

Prior to the drilling of an oil or natural gas well, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our operators' failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, our business and cash available for dividends may be adversely affected.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that may have greater resources. Many of these companies explore for and produce oil and natural gas, carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties, mineral interests and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices than operators of our mineral and royalty acreage. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Our ability to acquire additional mineral, royalty, overriding royalty, net profits and similar interests in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for these and other oil and natural gas properties. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations, can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for our operators in meeting well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Regulation

The following disclosure describes regulation more directly associated with operators of oil and natural gas properties, including our current operators, and other owners of working interests in oil and natural gas properties. To the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties, we would be directly subject to the same regulations described below. For purposes of this section, where applicable, references to "we," "us," and "our" refer to Viper Energy, Inc., to the extent the company were to acquire working interests in the future as well as to any operators of our properties, including our current operators.

Oil and natural gas operations are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases the cost of doing business.

Environmental Matters. Oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities; limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas; require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits; result in the suspension or revocation of necessary permits, licenses and authorizations; require that additional pollution controls be installed; and impose substantial liabilities for pollution resulting from operations. Liability under such laws and regulations is often strict (i.e., no showing of "fault" is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our business and prospects.

Waste Handling. The Resource Conservation and Recovery Act, or the RCRA, as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under the RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent non-hazardous waste requirements. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in the U.S. Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and natural gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and natural gas waste were not necessary at that time. Any changes in such laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, which we refer to as CERCLA or the "Superfund" law, and analogous state laws, generally impose liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed "responsible parties" are subject to strict liability that, in some circumstances, may be joint and several for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such "hazardous substances" have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," or the CWA, the Safe Drinking Water Act, the Oil Pollution Act, or the OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit.

The scope of waters regulated under the CWA has fluctuated in recent years. On January 18, 2023, the EPA and the U.S. Army Corps of Engineers, or the Corps, jointly promulgated final rules expanding the scope of waters protected under the CWA. However, on May 25, 2023, the United States Supreme Court issued an opinion substantially narrowing the scope of "waters of the United States" protected by the CWA. On September 8, 2023, the EPA and the Corps published a final rule conforming their regulations to the decision. These recent actions have provided some clarity. However, to the extent the EPA and the Corps broadly interpret their jurisdiction and expand the range of properties subject to the CWA's jurisdiction, we or third-party operators could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants, which regulations are discussed in more detail below under the caption "—Regulation of Hydraulic Fracturing." Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Non-compliance with the CWA or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions. The federal Clean Air Act, or the CAA, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal CAA that establish new emission controls for oil and natural gas production and processing operations, which are discussed in more detail below in "—Regulation of Hydraulic Fracturing." Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. For example, the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022, or the IRA, include billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration. Also, in March 2024, the EPA finalized ambitious rules to reduce harmful air pollutant emissions, including greenhouse gases, from light-, medium-, and heavy-duty vehicles beginning in model year 2027. These incentives and regulations could accelerate the transition of the economy away from the use of fossil fuels toward lower- or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we produce and sell and adversely impact our business. In addition, the IRA imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA amends the CAA to impose a fee on the emission of methane that exceeds an applicable waste emissions threshold from sources required to report their greenhouse gas emissions to the EPA, including those sources in offshore and onshore petroleum and natural gas production and gathering and boosting source categories. However, on January 20, 2025, President Trump signed multiple executive orders seeking to reverse many of these climate rules and incentives, including pausing the disbursement of funds under the IRA and eliminating the "electric vehicle mandate." Despite this shift, numerous proposals have been made and are likely to continue to be made at the international, regional and state levels of government that are intended to limit emissions of greenhouse gases by enforceable requirements and voluntary measures.

On November 18, 2024, the EPA published a final rule on the methane emissions charge, which became effective on January 17, 2025. The methane emissions charge must be paid no later than August 31 of the year following the reporting period and starts at $900 per ton of methane in 2024, increases to $1,200 in 2025 and will be set at $1,500 for 2026 and each year after. Calculation of the fee is based on methane emissions that exceed certain thresholds established in the IRA. The methane emissions charge could increase our operating costs, which could adversely impact our business, financial condition and cash flows.

The EPA has also finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and almost one-half of the states have taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and natural gas operations. For example, on November 4, 2020, the Texas Railroad Commission adopted new guidance on when flaring is permissible, requiring operators to submit more specific information to justify the need to flare or vent gas.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Paris Agreement went into effect on November 4, 2016. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its greenhouse gas emissions by 50-52 percent below 2005 levels in 2030. In November 2021, in connection with the 26th Conference of the Parties in Glasgow, Scotland, the United States and other world leaders made further commitments to reduce greenhouse gas emissions, including reducing global methane emissions by at least 30% by 2030 from 2020 levels. More than 150 countries have now signed on to this pledge. At the 28th Conference of the Parties in the United Arab Emirates, world leaders agreed to transition away from fossil fuels in a just, orderly and equitable manner and to triple renewables and double energy efficiency globally by 2030. Additionally, the Biden Administration announced a new climate target for the United States on December 19, 2024, which includes a 61 to 66 percent reduction in economy-wide net greenhouse gas emissions by 2035, as compared to 2005 levels. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the international climate commitments. However, on January 20, 2025, President Trump issued an executive order directing the United States Ambassador to the United Nations to immediately withdraw from the Paris Agreement, and on January 27, 2025, the United States' Acting Ambassador to the United Nations submitted a notification of withdrawal from the Paris Agreement, which is set to become effective one year after notification on January 27, 2026.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of the U.S. Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act.

On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

On August 16, 2012, the EPA published final regulations under the federal CAA that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, on August 13, 2020, in response to an executive order by President Trump to review and revise unduly burdensome regulations, the EPA amended the 2012 and 2016 New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. On June 30, 2021, President Biden signed into law a joint resolution of the U.S. Congress disapproving the 2020 amendments (with the exception of some technical changes) thereby reinstating the 2012 and 2016 New Source Performance standards. The EPA expects owners and operators of regulated sources to take "immediate steps" to comply with these standards. Additionally, on March 8, 2024, the EPA published a final rule to expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries, and prohibiting venting of natural gas in certain situations. These new standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions, which may increase our compliance or operating costs.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy and the Department of the Interior have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted legislation, effective September 1, 2011, requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. The Texas Railroad Commission adopted rules and regulations implementing this legislation that apply to all wells for which the Texas Railroad Commission issues an initial drilling permit after February 1, 2012. The law requires that the well operator disclose the list of chemical ingredients subject to the requirements of Federal Occupational Safety and Health Act for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Also, in May 2013, the Texas Railroad Commission adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The rules took effect in January 2014. Additionally, on October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Texas Railroad Commission’s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits and temporarily suspend operations for waste disposal wells. For example, in September 2021, the Texas Railroad Commission curtailed the amount of water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin, and has subsequently suspended some permits there and expanded the restrictions to other areas. In addition, the Texas Railroad Commission has imposed monitoring and reporting requirements for any new disposal well permitted in the Permian Basin. These restrictions on the disposal of produced water, a moratorium on new produced water wells, and additional monitoring and reporting requirements could result in increased operating costs, forcing our operators or their vendors to truck produced water, recycle it or pump it through the pipeline network or other means, all of which could be costly. Our operators or their vendors may also limit disposal well volumes, disposal rates and pressures or locations, or require them to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling activity in the affected parts of the Permian Basin less economical and adversely impact our business.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases the cost of doing business, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production. The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, the U.S. Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by the U.S. Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. The operations of our operators are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following; the location of wells; the method of drilling and casing wells; the timing of construction or drilling activities, including seasonal wildlife closures; the rates of production or "allowables"; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas that our operators can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure our stockholders that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas. Although the Corps does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales. Historically, federal legislation and regulatory controls have affected the price and marketing of natural gas. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales." Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, the U.S. Congress could reenact price controls in the future.

Crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act, and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operators to the same extent as to our or their competitors.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations our operators can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

We do not have any employees. Since the Conversion, the business and affairs of the Company are overseen by our board of directors, rather than the General Partner, which, pre-Conversion oversaw the business and affairs of the Partnership, our predecessor, as its general partner. Further, post-Conversion, Diamondback continues to provide personnel and general and administrative services to the Company, including the services of the executive officers and other employees, pursuant to the services and secondment agreement in a similar manner as Diamondback previously provided to the General Partner. Please see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes in Item 8. Financial Statements and Supplementary Data of this report. All of the individuals that conduct our business, including our executive officers, are employed by Diamondback.

Facilities

Our principal executive offices are located in Midland, Texas and are owned by Diamondback. We believe that these facilities are adequate for our current operations.

Availability of Company Reports

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge on the Investors page of our website at www.viperenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC. Reports filed or furnished with the SEC are also made available on its website at www.sec.gov.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are also described in Items 1 and 2. Business and Properties, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk of this report. These risks are not the only risks we face. We could also face additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks actually occurs, it could materially harm our business, financial condition or results of operations and the trading price of our shares could decline.

Risks Related to Our Business

Market conditions for oil and natural gas, and particularly volatility in prices for oil and natural gas, have in the past adversely affected, and may in the future adversely affect, our revenue, cash flows, profitability, growth and production.

From the beginning of 2022 through the end of 2024, NYMEX WTI has ranged from $65.75 to $123.70 per Bbl, and the NYMEX Henry Hub price of natural gas has ranged from $1.58 to $9.68 per MMBtu, with seven-year highs reached in 2023. The war in Ukraine, the Israel-Hamas War, rising interest rates, global supply chain disruptions, concerns about a potential economic downturn or recession, recent measures to combat persistent inflation, and actions taken by OPEC and its non-OPEC allies, collectively OPEC+, continued to contribute to economic and pricing volatility. These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. If the prices of oil and natural gas decline, our operations and financial condition may be materially and adversely affected.

Diamondback and certain of our other operators increased production on our acreage during 2024, but continued to exercise capital discipline by using the majority of their excess cash flow for debt repayment and/or return to their stockholders rather than expanding their drilling programs. We cannot reasonably predict whether production levels will remain at current levels or the impact the full extent of the events above may have on our industry and our business.

Based on the current commodity pricing environment and industry conditions, we did not record any impairments in 2024. However, if commodity prices fall below current levels, we may be required to record impairments in future periods and such impairments could be material. Further, if commodity prices decrease, our production, proved reserves and cash flows will be adversely impacted. Lower oil and natural gas prices may also result in a reduction in the borrowing base under the Operating Company's revolving credit facility, which may be determined at the discretion of our lenders.

Other significant factors that are likely to continue to affect commodity prices in future periods include, but are not limited to, the effect of U.S. energy, monetary and trade policies, U.S. and global economic conditions, U.S. and global political and economic developments, including the new administration's energy and environmental policies, all of which are beyond our control. Our business may be also adversely impacted by any future government rule, regulation or order that may impose production limits, as well as pipeline capacity and storage constraints, in the Permian Basin where we have mineral and royalty interests. We cannot predict the ultimate impact of these factors on our business, financial condition and cash available for dividends to our stockholders.

Our commodity price derivatives could result in financial losses, may fail to protect us from declines in commodity prices, prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty credit risk.

We use fixed price swap contracts, fixed price basis swap contracts and costless collar contracts with corresponding put and call options to reduce price volatility associated with certain of our royalty income. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX WTI pricing (WTI Cushing and Argus WTI Midland) and with natural gas derivative settlements based on the NYMEX Henry Hub and Waha Hub pricing. By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk and market risk. At settlement, market prices for commodities may exceed the contract prices in our commodity price derivatives agreements, resulting in our need to make significant cash payments to our counterparties. Further, by using commodity derivative instruments, we expose ourselves to credit risk if we are in a positive position at contract settlement and the counterparty fails to perform under the terms of the derivative contract. Our counterparties have been determined to have an acceptable credit risk; therefore, we do not require collateral from our counterparties. By using derivative instruments, we may be prevented from fully realizing the benefits of increases in the prices of oil, natural gas liquids and natural gas above the price levels of the commodity price derivatives used to manage price risk.

For additional information regarding our use of commodity price derivatives and our outstanding derivative contracts as of December 31, 2024, see Note 10—Derivatives in Item 8. Financial Statements and Supplementary Data, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk of this report.

The IRA and other risks relating to climate change could accelerate the transition to a low carbon economy and could impose new costs on our operations that may have a material and adverse effect on us.

Governmental and regulatory bodies, investors, consumers, industry and other stakeholders have been increasingly focused on climate change matters in recent years. This focus, together with changes in consumer and industrial/commercial behavior, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in; (i) the enactment of climate change-related regulations, policies and initiatives by governments, investors, and other companies, including alternative energy or "zero carbon" requirements and fuel or energy conservation measures, (ii) technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in wind, solar and hydrogen power, as well as battery technology), (iii) increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles), and (iv) development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services.

Any of these developments may reduce the demand for products manufactured with (or powered by) hydrocarbons and the demand for, and in turn the prices of, the oil and natural gas that we produce and sell, which would likely have a material adverse impact on us. The enactment of climate change-related regulations, policies and initiatives may also result in increases in our compliance costs and other operating costs and have other adverse effects, such as a greater potential for governmental investigations or litigation.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. For example, the Infrastructure Investment and Jobs Act and the IRA include billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration. Also, in March 2024, the EPA finalized ambitious rules to reduce harmful air pollutant emissions, including greenhouse gases, from light-, medium-, and heavy-duty vehicles beginning in model year 2027. These incentives and regulations could accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we produce and sell and adversely impact our business. Additionally, the IRA imposes the first ever federal fee on greenhouse gas emissions through a methane emissions charge, which could increase our operating costs and thereby adversely impact our business, financial condition and cash flows. On January 20, 2025, President Trump signed multiple executive orders seeking to reverse these climate incentives, including pausing the disbursement of funds under the IRA. The same day, President Trump also issued executive orders to encourage fossil fuel production and exploration on federal lands and waters, while moving away from incentivizing renewable energy and electric vehicles. It is unclear what effect these actions will have.

In addition to potentially reducing (i) demand for our oil and natural gas and (ii) the availability of oilfield services and midstream and downstream customers, any further regulatory or other climate change initiatives, to the extent they continue, may create reputational risks associated with the exploration for, and production of, hydrocarbons, which may adversely affect the availability and cost to us of capital. For example, in recent years, certain stakeholders and capital providers sought to restrict or seek more stringent conditions with respect to their investment in or financing of certain carbon intensive sectors. If financial institutions and other investors refuse to invest in or provide capital to the oil and gas sector in the future because of these reputational risks, that could result in capital being unavailable to us, or only at a significantly increased cost.

For further discussion regarding the risks to us of climate change-related regulations, policies and initiatives, see Item 1 and 2. Business and Properties—Regulation—Climate Change of this report.

Changing political and social perspectives on climate change and other environmental, social and governance factors may create risks and uncertainties impacting our business.

In recent years, increased attention to global climate change resulted in increased investor attention and an increased risk of public and private litigation.

Perspectives on environmental, social and governance (“ESG”) considerations continue to evolve, and we cannot currently predict how regulators’, investors’ and other stakeholders’ views on ESG matters may affect the regulatory and investment landscape and affect our business, financial condition, and results of operations. If we do not, or are perceived to not, adapt or comply with investor or stakeholder expectations and standards on ESG matters, we may suffer from reputational damage and our business, financial condition and results of operations could be materially and adversely affected.

The SEC published final rules on March 28, 2024 relating to the disclosure of a range of climate-related risks and other information. Several lawsuits have been filed challenging the rules. In April 2024, the SEC agreed to pause the rules to facilitate an orderly judicial resolution. To the extent the rules are implemented, we and/or our customers could incur increased costs related to the assessment and disclosure of climate-related information.

Additionally, cities, counties, and other governmental entities in several states in the U.S. have filed lawsuits against energy companies seeking damages allegedly associated with climate change. Similar lawsuits may be filed in other jurisdictions. If any such lawsuits were to be filed against us, whether due to our activities or the activities of the acquired entities or operations prior to their acquisition by us, we could incur substantial legal defense costs and, if any such litigation were adversely determined, we could incur substantial damages. Any of these climate change-related litigation risks could result in unexpected costs, negative sentiments about our company, disruptions to our business, and increases to our operating expenses, which in turn could have an adverse effect on our business, financial condition and cash flow.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash available to return to our stockholders.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

We may not have sufficient available cash to pay any quarterly dividend on our Common Stock, our cash available for dividends may vary significantly from quarter to quarter and our board of directors may in the future modify or revoke our cash dividend policy at any time at its discretion. Our dividend policy could limit our ability to grow and make acquisitions.

We may not have sufficient cash available to pay base or variable dividends to our common stockholders each quarter. Furthermore, our cash dividend policy does not require us to pay dividends on a quarterly basis or otherwise. The amount of cash we have to distribute each quarter principally depends upon the amount of royalty income we generate, which is dependent upon the volumes of production sold and the prices that our operators realize from the sale of such production. In addition, the actual amount of cash we will have to distribute each quarter under our cash dividend policy will be reduced by payments in respect of income taxes, debt service and other contractual obligations and fixed charges, increases in reserves for future operating or capital needs that the board of directors may determine is appropriate, lease bonus income, distribution equivalent rights payments and preferred dividends, if any, and any common share repurchases. The board of directors may further modify or revoke our dividend policy at any time in the future at its discretion. During 2022, the board of directors approved a dividend policy, effective beginning with the Company’s dividend payable for the third quarter of 2022, consisting of a base and variable dividend, that takes into account capital returned to stockholders via our Common Stock repurchase program. For information regarding our dividend policy and the recent modifications, see Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Cash Dividend Policy and Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of this report. As a result, quarterly dividends paid to our stockholders may vary significantly from quarter to quarter and may be zero.

As a result of our cash dividend policy, we will have limited cash available to reinvest in our business or to fund acquisitions, and we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and growth capital expenditures. As such, to the extent we are unable to finance growth externally, our dividend policy will significantly impair our ability to grow.

To the extent we issue additional shares in connection with any acquisitions or growth capital expenditures or as in-kind dividends, the payment of dividends on those additional shares may increase the risk that we will be unable to maintain or increase our per share dividend level.

We depend on a small number of operators for a substantial portion of the development and production on our mineral and royalty acreage. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of an operator to adequately and efficiently develop and operate our acreage could have an adverse effect on our expected growth and our results of operations.

The failure of our operators to adequately or efficiently perform operations or an operator's failure to act in ways that are in our best interests could reduce production and revenues. Any development and production activities on our properties are subject to our operators' reasonable discretion. The level, success and timing of drilling and development activities on our properties, and whether the operators elect to drill any additional wells on our acreage, depends on a number of factors that will be largely outside of our control, including: commodity prices; the timing and amount of capital expenditures by our operators, which could be significantly more than anticipated; the ability of our operators to access capital; the availability, high cost or shortages of rigs and other suitable drilling equipment, raw materials, supplies and oilfield services; the availability of production and transportation infrastructure and qualified operating personnel; regulatory restrictions; the operators' expertise, operating efficiency and financial resources; approval of other participants in drilling wells; the operators' expected return on investment in wells drilled on our acreage as compared to opportunities in other areas; the selection of technology; the selection of counterparties for the sale of production; and the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake such activities in an unanticipated fashion, which may result in significant fluctuations in our royalty income and cash available for dividends to our stockholders. If reductions in production by the operators are implemented on our properties and sustained, our revenues may also be substantially affected. Additionally, if an operator were to experience financial difficulty, the operator might not be able to pay its royalty payments or continue its operations, which could have a material adverse impact on us.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures by operators than we currently anticipate.

Approximately 16% of our total estimated proved reserves as of December 31, 2024 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations by the operators on our mineral and royalty acreage. The reserve data included in the reserve reports of our independent petroleum engineers assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill, complete and develop such reserves, or further decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

We may not be able to terminate our leases if any of our operators declare bankruptcy, and we may experience delays and be unable to replace operators that do not make royalty payments.

Generally, a failure on the part of our operators to make royalty payments to us gives us the right to terminate the applicable lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to bankruptcy proceedings that could prevent the execution of a new lease or the assignment of the existing lease to another operator. In addition, if we enter into a new lease, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

The producing properties in which we have mineral and royalty interests are primarily concentrated in the Permian Basin of West Texas, making us vulnerable to risks (including weather-related risks) associated with a single geographic area. In addition, a large amount of our proved reserves is attributable to a small number of producing horizons within this area.

The producing properties in which we have mineral and royalty interests are currently geographically primarily concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints faced by our operators or their customers, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids on our mineral and royalty acreage, and extreme weather conditions and their adverse impact on production volumes, availability of electrical power, road accessibility and transportation facilities on our mineral and royalty acreage.

Extreme regional weather events may occur that can affect our operators' suppliers or customers, which could adversely affect us. For example, a significant hurricane or similar weather event could damage refining and other oil and natural gas-related facilities on the Gulf Coast of Texas and Louisiana, which (if significant enough) could limit the availability of gathering and transportation facilities across Texas and could then cause production in the Permian Basin (potentially including production on our mineral and royalty acreage) to be curtailed or shut in or (in the case of natural gas) flared. Climate changes may also increase the frequency and severity of significant weather events over time. Further, any increase in flaring of natural gas production on our mineral and royalty acreage due to weather-related events, or otherwise, could expose us to reputational risks and adversely impact our or our operators' contractual and other business relationships. Any of the above-referenced events could have a material adverse effect on us. Likewise, a weather event could reduce the availability of electrical power, road accessibility, and transportation facilities, which could have an adverse impact on production volumes on our mineral and royalty acreage (and therefore on our financial condition and results of operations).

In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our mineral and royalty acreage, we could experience any of these conditions at the same time, resulting in a relatively greater impact on us than they might have on other companies that have a more diversified portfolio of assets. Such delays or interruptions could have a material adverse effect on our business, financial condition and cash flow.

In addition to the geographic concentration of our mineral and royalty acreage, as of December 31, 2024, most of our proved reserves are concentrated in the Wolfberry resource play in the Midland Basin. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause our operators to permanently or temporarily shut-in all of the wells on our mineral and royalty acreage.

Our future success depends on the development or acquisition of additional reserves, and our failure to successfully identify, complete and integrate acquisitions of properties or businesses could slow our growth and adversely affect our results of operations and cash available for dividends.

Our future success depends upon the development or acquisition of additional oil and natural gas reserves that are economically recoverable, as our proved reserves will generally decline as reserves are depleted. To increase reserves and production, we would need to undertake replacement activities or use third-party operators to undertake development, exploration and other replacement activities, requiring substantial capital expenditures. Neither we nor our third-party operators may have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities. Such activities by our third-party operators may not result in significant additional reserves and efforts to drill productive wells at low finding costs may be unsuccessful. In addition, we do not expect to retain cash from our operations for replacement capital expenditures. Furthermore, although our revenues and cash available for dividends may increase if prevailing oil and natural gas prices increase significantly, finding costs for additional reserves could also increase.

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including; recoverable reserves, future oil and natural gas prices and their applicable differentials, operating costs and potential environmental and other liabilities. The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems including title defects or environmental issues, which, if material, can render an interest worthless, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Environmental or other regulatory issues may arise with respect to acquired entities or operations years after the acquisitions, any of which can adversely affect our results of operations, financial condition and cash available for dividends. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Significant acquisitions and other strategic transactions may involve other risks that may cause our business to be adversely impacted, including diversion of our management's attention to evaluating and negotiating such transactions and our failure to realize the full benefit that we expect in estimated proved reserves, production volume or other benefits anticipated therefrom, or to realize these benefits within the expected time frame.

We may not be able to complete acquisitions or do so on commercially acceptable terms, as our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, our future acquisitions may be in geographic regions in which we do not currently hold properties. If we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements and other unforeseen difficulties. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations, the process of which may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. Any of the unfavorable circumstances mentioned above could have a material adverse effect on our financial condition, results of operations and cash available for dividends. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations and cash available for dividends. See also *"Risks Related to the Pending 2025 Drop Down"* below for a description of risk factors specific to that transaction.

Project areas on our properties, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Project areas on our properties are in various stages of development, ranging from project areas with current drilling or production activity to project areas that have limited drilling or production history. If the wells in the process of being completed are on our property and do not produce sufficient revenues or if dry holes are drilled, our financial condition, results of operations and cash available for dividends may be materially affected.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs, if any. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs, if any, may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that we ultimately recover being different from our reserve estimates. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage.

We are dependent on electrical power, internet and telecommunication infrastructure and information and computer systems. If any of these systems are compromised or unavailable, our business could be adversely affected.

We are dependent on electric power, internet and telecommunication infrastructure and Diamondback's information systems and computer based programs. If any of such infrastructure, systems or programs were to fail or become unavailable or compromised, or create erroneous information in our hardware or software network infrastructure, our ability to safely and effectively conduct our business will be limited and any such consequence could have a material adverse effect on our business.

We are subject to cybersecurity risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

We rely extensively on Diamondback's information technology systems, including internally developed software, data hosting platforms, real-time data acquisition systems, third-party software, cloud services and other internally or externally hosted hardware and software platforms, to (i) estimate our oil and natural gas reserves, (ii) process and record financial and operating data, and (iii) communicate with our management and board of directors, as well as, our vendors, suppliers and other third parties. Further, our reliance on technology has increased due to the increased use of personal devices, remote communications and work-from-home or hybrid work practices.

Risks from cybersecurity threats have not materially affected, and are not currently anticipated to materially affect, our company, including our business strategy, results of operations and financial condition. However, our systems and networks (which are provided by Diamondback), and those of its vendors, service providers and other third-party providers, may become the target of cybersecurity attacks, including, without limitation, denial-of-service attacks; malicious software; data privacy breaches by insiders or others with authorized access; cyber or phishing-attacks; ransomware; attempts to gain unauthorized access to our data and Diamondback's systems; and other electronic security breaches. Security incidents can also occur as a result of non-technical issues, such as physical theft. More recently, advancements in artificial intelligence ("AI") may pose serious risks for many of the traditional tools used to identify individuals, including voice recognition (whether by machine or the human ear), facial recognition or screening questions to confirm identities. In addition, generative AI systems may also be used by malicious actors to create more sophisticated cyber-attacks (i.e., more realistic phishing or other attacks). The advancements in AI could lead to an increase in the frequency of identity fraud or cyberattacks (whether successful or unsuccessful), which could cause us or our providers to incur increasing costs, including costs associated with additional personnel, protection technologies and policies and procedures and third-party experts and consultants. If any of these security breaches were to occur, we could suffer disruptions to our operations, normal business functions and other aspects of our business.

Diamondback provides personnel and general and administrative services to us, including personnel and infrastructure that underlie our cybersecurity risk management program. In connection therewith, Diamondback has implemented and invested in, and will continue to implement and invest in, controls, procedures and protections (including internal and external personnel), and has implemented a cybersecurity governance program, that are designed, in each case, to protect its systems; identify and remediate, on a regular basis, vulnerabilities in its systems and related infrastructure and monitor and mitigate the risk of data loss and other cybersecurity threats. Diamondback has also engaged third-party consultants to conduct penetration testing and risk assessments. Such measures, however, cannot entirely eliminate cybersecurity threats and may prove to be ineffective. As cyber incidents continue to evolve, Diamondback may be required to expend additional resources (for which we may be partially responsible) to continue to modify or enhance protective measures or to investigate and remediate any vulnerability to cyber incidents. Diamondback maintains specialized insurance for possible liability resulting from a cyberattack on its assets, however, we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that Diamondback will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and cash flows. See " Item 1C—Cybersecurity" below for additional information.

Evolving privacy-related laws could give rise to liabilities, which could adversely impact our business, results of operations or financial condition.

A variety of U.S. federal, state and international laws and regulations govern the collection, use, retention, sharing and security of personal data. All 50 states have enacted legislation on data breach notification requirements and many states continue to enact laws on matters of privacy, data protection and cybersecurity. The existing privacy-related laws and regulations are evolving and subject to potentially differing interpretations. In addition, various U.S. federal, state and foreign legislative and regulatory bodies continue to enact new laws regarding privacy and data protection, as well as expand the scope of existing laws. For example, Texas recently passed the Texas Data Privacy and Security Act, which establishes new laws for collecting, storing, processing, and selling consumer information. Several other states, such as California, Utah, Colorado, Virginia, Connecticut, Michigan, Ohio, Pennsylvania, and New Jersey, among others, have proposed or passed legislation regarding data privacy and use. We cannot predict the impact of any such evolving privacy-related laws on our business, results of operations or financial condition, but may find it necessary to enhance the existing systems and procedures, which may involve substantial expense or distraction from other aspects of our business. In addition, any violations of applicable privacy-related laws or regulations may require us to address legal claims, sustain monetary penalties or incur other liabilities, as well as cause reputational damage, any of which could adversely impact our business, results of operations or financial condition.

Risks Related to Our Indebtedness

Implementing our capital programs may, under certain circumstances, require an increase in our total leverage through additional debt issuances. In addition, a significant reduction in availability under the revolving credit facility and the inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.

As a result of our cash dividend policy, we have limited cash available to reinvest in our business or to fund acquisitions and have historically relied on availability under the Operating Company's revolving credit facility to fund a portion of our capital expenditures and for other purposes. We expect that we will continue to fund a portion of our capital expenditures and other needs with borrowings under the revolving credit facility and from the proceeds of debt and equity offerings. In the past, we have created availability under the revolving credit facility by repaying outstanding borrowings with the proceeds from equity and debt offerings. We cannot assure you that we will choose to or be able to access the capital markets to repay any such future borrowings. If the availability under the revolving credit facility were reduced, and we were otherwise unable to secure other sources of financing, we may be required to curtail our capital expenditures, which could result in an inability to complete acquisitions or finance the capital expenditures necessary to replace our reserves.

Restrictive covenants in the Operating Company's revolving credit facility, the indentures governing the Notes and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.

The Operating Company's revolving credit facility and the indentures governing the Notes outstanding contain, and the terms of any future indebtedness may contain, restrictive covenants that limit our and the Operating Company's ability to, among other things: incur or guarantee additional indebtedness; make certain investments; create additional liens; sell or transfer assets; lease property as a lessee; issue redeemable or preferred equity; voluntarily redeem or prepay debt (including the Notes); merge or consolidate with another entity; pay or declare dividends; designate certain of our subsidiaries as unrestricted subsidiaries; create unrestricted subsidiaries; engage in transactions with affiliates; enter into gas imbalances, take-or-pay and similar agreements; and enter into certain swap agreements.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us and the Operating Company by the restrictive covenants contained in the revolving credit facility and the indentures that govern the Notes. In addition, the revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

Our and the Operating Company's future ability to comply with these restrictions and covenants is uncertain and will be affected by the levels of cash flow from our operations and other events or circumstances beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A breach of any of these restrictive covenants could result in default under the revolving credit facility. If a default occurs, the lenders under the revolving credit facility may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due and payable, which would result in an event of default under the indentures governing the Notes. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we and the Operating Company are unable to repay outstanding borrowings when due, the lenders under the revolving credit facility will also have the right to proceed against the collateral granted to them to secure the indebtedness. If the indebtedness under the revolving credit facility and the Notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Any significant reduction in the borrowing base under the Operating Company's revolving credit facility as a result of the periodic borrowing base redeterminations, or otherwise, may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under the revolving credit facility if required as a result of a borrowing base redetermination.

A decline in commodity prices could result in a redetermination that lowers the borrowing base. Any significant reduction in the borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under the revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we and the Operating Company would be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of the borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Servicing our indebtedness requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial indebtedness.

Our ability to make scheduled payments of the principal, to pay interest on or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. We are dependent on cash flow generated by the Operating Company to repay the Notes. The Operating Company's business may not generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If the Operating Company is unable to generate such cash flow, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional capital on terms that may be onerous or highly dilutive. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. In the absence of such cash flows, we could have substantial liquidity problems and might be required to sell material assets to attempt to meet our debt service and other obligations. The Operating Company's revolving credit facility and the indentures governing the Notes outstanding restrict our ability to use the proceeds from asset sales. We may not be able to consummate those asset sales to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on our financial condition.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our or the Operating Company's borrowing costs.

The borrowings under the Operating Company's revolving credit facility expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under the Operating Company's revolving credit facility. The terms of the Operating Company's revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate that, since November 2022 has been tied to SOFR. SOFR tends to fluctuate based on multiple factors, including general short-term interest rates, rates set by the U.S. Federal Reserve, and other central banks and general economic conditions. We have not hedged our interest rate exposure with respect to our floating rate debt. The Operating Company's weighted average interest rate on borrowings under its revolving credit facility was 7.34% during the year ended December 31, 2024. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Risks Inherent in an Investment in Us

Diamondback controls us and its interests may conflict with ours or yours in the future.

As of the date of this Annual Report on Form 10-K, Diamondback beneficially owned approximately 39% of the outstanding voting power of our capital stock, and we currently estimate that following the closing of the Pending 2025 Drop Down, Diamondback will beneficially own approximately 52% of our outstanding Common Stock, on a fully diluted basis. For so long as Diamondback continues to have voting power over a significant percentage of our capital stock, even at times when such amount is less than 50%, it will be able to significantly influence the composition of our board of directors and the approval of actions requiring stockholder approval. Although the holders of our Common Stock are entitled to vote on all matters on which stockholders of a corporation are generally entitled to vote on under the Delaware General Corporation Law (the "DGCL"), including the election of our board of directors, pursuant to our certificate of incorporation, for so long as Diamondback and any of its subsidiaries collectively beneficially own at least 25% of our outstanding Common Stock (i) Diamondback has the right to designate up to three persons to serve as members of our board of directors, and (ii) our board of directors may not appoint any person other than a Diamondback seconded employee as an executive officer of our company unless such appointment is approved, in advance, by either (x) Diamondback (which approval may not be unreasonably withheld or conditioned), or (y) the affirmative vote of the holders of at least 80% of the voting power of our capital stock. Currently, there are two Diamondback designees to our board of directors—Travis Stice and Kaes Van't Hof. Further, in connection with the Conversion, we entered into the services and secondment agreement with Diamondback E&P LLC and OpCo, pursuant to which Diamondback continues to provide personnel and general and administrative services to us and OpCo, including the services of the executive officers and other employees, in a similar manner as Diamondback provided to us before the Conversion. Accordingly, Diamondback will have significant influence with respect to our board of directors, management, business plans and policies, including the appointment and removal of our officers. In particular, for so long as Diamondback continues to beneficially own a significant percentage of our capital stock, it will be able to cause or prevent a change of control of our company or a change in the composition of our board of directors and could preclude any unsolicited acquisition of our company. The concentration of ownership could deprive you of an opportunity to receive a premium for your shares of Common Stock as part of a sale of our company and ultimately might affect the market price of our Common Stock.

We do not have any employees, and we rely solely on the employees of Diamondback to manage our business. The management team of Diamondback, which includes the individuals who manage us, also perform similar services for Diamondback and certain of its affiliates, and thus are not solely focused on our business.

We do not have any employees and we rely solely on Diamondback to provide us with personnel and general and administrative services, including the services of the executive officers, senior management and other employees, under the terms and conditions of the services and secondment agreement discussed above. Because Diamondback provides services to us that are similar to those it performs for itself and its affiliates, it may not have sufficient human, technical and other resources to provide those services at a level that it would be able to provide to us if it were solely focused on our business and operations. Diamondback may make internal decisions on how to allocate its available resources and expertise that may not always be in our best interest compared to Diamondback's interests. There is no requirement that Diamondback favor us over itself or others in providing its services. If Diamondback does not devote sufficient attention to the management and operation of our business or otherwise breaches the provisions of the services and secondment agreement, our financial results may suffer and our ability to pay dividends to our stockholders may be reduced. Many key responsibilities within our business have been assigned to a small number of individuals. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of the executive team could disrupt our business. Further, we do not maintain "key person" life insurance policies on any of our executive team or other key personnel. As a result, we are not insured against any losses resulting from the death of these key individuals.

State and local income and other tax reimbursements due to Diamondback for our share of state and local and other taxes borne by Diamondback will reduce cash available for dividends to our common stockholders.

We have entered into a tax sharing agreement with Diamondback pursuant to which we are required to reimburse Diamondback for our share of state and local income and other taxes borne by Diamondback as a result of our results being included in a combined or consolidated tax return filed by Diamondback. The reimbursement of our share of state and local income and other taxes borne by Diamondback will reduce the amount of cash available for dividends from us to our common stockholders.

The market price of our shares of Class A Common Stock could be adversely affected by sales of substantial amounts of our Class A Common Stock in the public or private markets.

Sales by holders of a substantial number of our Class A Common Stock in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our Class A Common Stock or could impair our ability to obtain capital through an offering of equity securities. In addition, we have provided registration rights to Diamondback and other parties. Pursuant to these registration rights, we have registered, under the Securities Act, all of the Class A Common Stock owned by Diamondback and those other parties for resale (including Class A Common Stock issuable in respect of the Class B Common Stock under the related exchange agreement).

U.S. tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and natural gas industry, including (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. These proposed changes in the U.S. tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flow.

On August 16, 2022, President Biden signed into law the IRA, which, among other changes, imposes a 15% corporate alternative minimum tax ("CAMT") on the "adjusted financial statement income" of certain large corporations (generally, corporations reporting more than $1 billion average adjusted pre-tax net income on their consolidated financial statements) for tax years beginning after December 31, 2022. If we are or become subject to CAMT including as a result of our affiliation with Diamondback, our cash tax obligations for U.S. federal income taxes could be significantly accelerated.

The IRA also imposes an excise tax of 1% on the fair market value of certain public company stock repurchases occurring on or after January 1, 2023. The excise tax is imposed on the repurchasing corporation, and the amount of the excise tax is generally 1% of the aggregate fair market value of the stock repurchased during the taxable year. However, for purposes of calculating the excise tax, repurchasing corporations are permitted to net the fair market value of certain new stock issuances against the fair market value of stock repurchases during the same taxable year. To the extent the 1% excise tax applies to repurchases of shares under our common stock repurchase program, the number of shares we repurchase and our cash flow may be affected.

The U.S. Treasury Department, the Internal Revenue Service and other standard-setting bodies are expected to issue additional guidance on how CAMT, stock buyback excise tax and other provisions of the IRA will be applied or otherwise administered that may differ from our interpretations. We continue to evaluate the IRA and its effect on our financial results and operating cash flow.

The provision of our certificate of incorporation requiring exclusive venue in the Court of Chancery in the State of Delaware for certain types of lawsuits may have the effect of discouraging lawsuits against us and our directors, officers and stockholders.

Our certificate of incorporation requires, to the fullest extent permitted by law, that any claim, demand, action, suit or proceeding, whether civil, criminal, administrative or investigative, and whether formal or informal, and including appeals, arising out of or relating in any way to our certificate of incorporation or any of our stock may only be brought in the Court of Chancery of the State of Delaware or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction. This provision may have the effect of discouraging lawsuits against us and our directors, officers and stockholders.

Our certificate of incorporation does not limit the ability of Diamondback and certain of its directors, principals, officers, employees and their respective affiliates to compete with us.

Our certificate of incorporation provides that none of Diamondback, any of its directors, principals, officers, employees or respective affiliates will have any duty to refrain from engaging, directly or indirectly, in the same business activities or similar business activities or lines of business in which we operate. In the ordinary course of their business activities, these persons may engage in activities where their interests conflict with our interests or those of our other stockholders.

These persons also may pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to the Company. In addition, these persons may have an interest in our pursuing acquisitions, divestitures and other transactions that, in their judgment, could enhance their investment, even though such transactions might involve risks to our common stockholders.

Anti-takeover provisions in our organizational documents and Delaware law might discourage or delay acquisition attempts for us that you might consider favorable.

Our certificate of incorporation and bylaws contain provisions that may make the merger or acquisition of our company more difficult without the approval of our board of directors. Among other things, these provisions would allow us to authorize the issuance of shares of one or more series of preferred stock, including in connection with a stockholder rights plan, financing transactions or otherwise, the terms of which series may be established and the shares of which may be issued without stockholder approval, and which may include super voting, special approval, dividend, or other rights or preferences superior to the rights of the holders of Common Stock; prohibit stockholder action by written consent unless such action is consented to by the board of directors; provide for certain limitations on convening special stockholder meetings; provide (i) that the board of directors is expressly authorized to make, alter, or repeal our bylaws, and (ii) that our stockholders may only amend our bylaws with the approval of at least a majority of all of the outstanding shares of our capital stock entitled to vote; and establish advance notice requirements for nominations for elections to our board or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Further, as a Delaware corporation, we are also subject to provisions of Delaware law which may impede or discourage a takeover attempt that our stockholders may find beneficial. These anti-takeover provisions and other provisions under Delaware law could discourage, delay or prevent a transaction involving a change in control of our company, including actions that our stockholders may deem advantageous, or could negatively affect the trading price of our Common Stock. These provisions could also discourage proxy contests and make it more difficult for you and other stockholders to elect directors of your choosing and to cause us to take other corporate actions you desire.

Our ability to pay base and variable dividends to the holders of our Class A Common Stock or make share repurchases under our repurchase program may be limited by requirements under our certificate of incorporation, our holding company structure, applicable provisions of Delaware law and contractual restrictions or obligations.

Under our current dividend policy, we pay quarterly base plus variable cash dividends on our Class A Common Stock. The outstanding shares of Class B Common Stock are entitled to an aggregate quarterly preferred dividend of $20,000 in cash. Other than the insignificant preferred dividend requirement, we are not required to pay dividends to our stockholders on a quarterly or other basis, and declaration of any other dividends in the future will be solely in the discretion of our board of directors, which may change our dividend policy at any time. Our ability to pay cash dividends to holders of our Class A Common Stock depends on a number of factors, including among other things, general economic and business conditions, our strategic plans and prospects, our businesses and investment opportunities, our financial condition and operating results, capital requirements and other anticipated cash needs, contractual restrictions and obligations, legal, tax and regulatory restrictions and other factors.

Additionally, as a holding company, our ability to pay dividends or repurchase shares of our Class A Common Stock is subject to the ability of our operating subsidiary OpCo and any future subsidiaries to provide cash to us. Viper Energy, Inc. has no material assets other than its membership interest in OpCo, which holds all of the mineral and royalty interests and other assets consolidated on our balance sheet.

Under the DGCL we may only pay dividends to our stockholders out of (i) our surplus, as defined and computed under the provisions of the DGCL, or (ii) our net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. If we do not have sufficient surplus or net profits, we will be prohibited by law from paying any such dividend. In addition, the terms of the OpCo’s revolving credit facility include, and any other debt instruments or financing arrangements may from time to time include covenants or other restrictions that could constrain our ability to pay dividends, make other distributions or repurchase shares of our Class A Common Stock. Our certificate of incorporation contains provisions authorizing us to issue series of preferred stock that may have designations, preferences, rights, powers and duties that are different from, and may be senior to, those applicable to our Class A Common Stock.

For additional information regarding stockholders’ equity and our repurchase program, see Note 7—Stockholders' Equity in Item 8. Financial Statements and Supplementary Data of this report.

Risks Related to the Pending 2025 Drop Down

Our ability to complete the Pending 2025 Drop Down is subject to various closing conditions outside of our control, including approval by the majority of unaffiliated stockholders and regulatory clearance.

The Pending 2025 Drop Down is subject to a number of conditions to closing as specified in the equity purchase agreement for the Pending 2025 Drop Down. These closing conditions include, among others, (i) the approval of the Pending 2025 Drop Down by (a) the holders of a majority of the voting power of our Common Stock entitled to vote on such proposal, voting together as a single class, at the special meeting of our stockholders, excluding the shares beneficially owned by Diamondback and its subsidiaries, and (b) the holders of a majority of our outstanding Common Stock, in each case as required by Delaware law, (ii) the expiration or termination of the waiting period under the HSR Act relating to the Pending 2025 Drop Down and (iii) the satisfaction or waiver of other customary closing conditions. The Equity Issuance is subject to the approval by our stockholders representing a majority of the total votes cast at the special meeting on such proposal, as required by the rules of the Nasdaq Stock Market LLC.

We expect to hold the special meeting of our stockholders and close the Pending 2025 Drop Down during the second quarter of 2025. No assurance can be given, however, that the requisite stockholder approvals or the HSR Act regulatory clearance will be obtained or that the other required closing conditions will be satisfied. Even if the requisite stockholder approvals and the HSR regulatory clearance are obtained, no assurance can be given as to the timing of such approval or clearance. Any delay in completing the Pending 2025 Drop Down could cause us not to be able to realize, or to be delayed in realizing, some or all of the benefits that we expect to achieve if the Pending 2025 Drop Down is successfully completed within its expected time frame. We cannot provide any assurance that these conditions will not result in the abandonment or delay of the Pending 2025 Drop Down. The occurrence of any of these events individually or in combination could have a material adverse effect on our results of operations and the trading price of our Class A Common Stock.

We may be unable to realize anticipated cash flows or other benefits from the Pending 2025 Drop Down.

Our ability to achieve the anticipated benefits from the Pending 2025 Drop Down will depend in part upon an assessment of several factors, including:

- recoverable reserves;
- future natural gas and oil prices and their appropriate differentials;
- existing and future production on the mineral and royalty acreage subject to the Pending 2025 Drop Down and Diamondback's plans with respect to such Diamondback-operated acreage;
- any title defects; and
- environmental and other regulatory, permitting and similar matters.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we have performed a review of the subject properties that we believe to be generally consistent with industry practices. Our review may not reveal all existing or potential problems or permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections will not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. The integration process may be subject to delays or changed circumstances, and we can give no assurance that the Endeavor Mineral and Royalty Interests will generate cash flow in accordance with our expectations. Significant acquisitions, such as the Pending 2025 Drop Down, and other strategic transactions may involve other risks that may cause our business to be adversely impacted, including:

- diversion of our management's attention to evaluating and negotiating significant acquisitions and strategic transactions; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity Risk Management Strategy

Diamondback provides us with personnel and general and administrative services pursuant to the services and secondment agreement, including the personnel and infrastructure that underlie our cybersecurity risk management program. In connection therewith, Diamondback has implemented and invested in, and will continue to implement and invest in, controls, procedures and protections (including internal and external personnel) that are designed to protect Diamondback's systems, identify and remediate on a regular basis vulnerabilities in Diamondback's systems and related infrastructure and monitor and mitigate the risk of data loss and other cybersecurity threats. Diamondback has also engaged third-party consultants to conduct penetration testing and risk assessments. Diamondback's cybersecurity program is informed by the National Institute of Standards and Technology ("NIST") Cybersecurity Framework and measured by the Maturity and Risk Assessment Ratings associated with the NIST Cybersecurity Framework and the Capability Maturity Model Integration.

Diamondback's cybersecurity risk management program is integrated into its overall enterprise risk management program, and shares common methodologies, reporting channels and governance processes that apply across the enterprise risk management program to other legal, compliance, strategic, operational, and financial risk areas that apply to us.

Diamondback's cybersecurity risk management program, which it provides to us under the services and secondment agreement, includes:

- risk assessments designed to help identify material cybersecurity risks to critical systems, information, products, services, and the broader enterprise IT and operational technology ("OT") environments;

- a security team principally responsible for managing (i) cybersecurity risk assessment processes, (ii) security controls, and (iii) its response to cybersecurity incidents;
- the use of external service providers, where appropriate, to assess, test, train or otherwise assist with aspects of its security controls;
- security tools deployed in the IT and OT environments for protection against and monitoring for suspicious activity;
- cybersecurity awareness training of its employees, including incident response personnel and senior management, including those who provide these services for us;
- cybersecurity tabletop exercises for members of its cybersecurity incident response team and legal department;
- a cybersecurity incident response plan that includes procedures for responding to cybersecurity incidents; and
- a third-party risk management process for service providers, suppliers, and vendors.

Cybersecurity Governance

Diamondback's cybersecurity governance program is led by its Senior Vice President and Chief Information Officer, with support from the internal information technology department. Diamondback's Senior Vice President and Chief Information Officer has over 20 years of technological leadership experience in the oil and gas industry, providing oversight of all information technology disciplines, including cybersecurity, networking, infrastructure, applications, and data management and protection. Diamondback's Senior Vice President and Chief Information Officer and his team, which consists of individuals who hold designations as Certified Information Systems Security Professional (CISSP), Certified Information Systems Auditor (CISA), CompTIASecurity+, and Department of Defense (DoD)-Cybersecurity General, are responsible for leading enterprise-wide cybersecurity strategy, policy, standards, architecture and processes. In addition, Diamondback's cybersecurity incident response team is responsible for responding to cybersecurity incidents in accordance with its Computer Security Incident Response Plan. Progress and developments in Diamondback's cybersecurity governance program are communicated to members of its and our executive team. Diamondback's and our management takes steps to remain informed about and monitor efforts to prevent, detect, mitigate and remediate cybersecurity risks and incidents through various means, which may include briefings from internal security personnel; threat intelligence and other information obtained from governmental, public or private sources, including third-party consultants engaged by Diamondback; and alerts and reports produced by security tools deployed in the enterprise IT and OT environments. While our board of directors is ultimately responsible for enterprise-wide risk oversight, the board's committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. In particular, the board's audit committee is responsible, among other things, for risk management relating to legal and regulatory requirements, including cybersecurity, which plays an integral role in the risk management strategy and continues to be an area of increasing focus for our board, the audit committee and management.

The audit committee of the board of directors receives quarterly updates on the status of Diamondback's cybersecurity governance program, including as related to new or developing initiatives and any security incidents that may occur, to the extent relevant to our program. Board members receive presentations on cybersecurity topics from Diamondback's Senior Vice President and Chief Information Officer as part of the board's continuing education on topics that impact public companies. Further, Diamondback's code of business conduct and ethics expects all employees to safeguard the electronic communications systems and related technologies of Diamondback and its subsidiaries, including us, from theft, fraud, unauthorized access, alteration or other damage and requires them to report any cyberattacks or incidents, improper access or theft to Diamondback's Chief Legal and Administrative Officer and Senior Vice President and Chief Information Officer. Diamondback's cybersecurity governance program also includes processes to assess cybersecurity risks related to third-party service providers, suppliers and vendors. Diamondback's vendor management process may include reviewing the cybersecurity practices of such providers, contractually imposing obligations on the providers, conducting security assessments and conducting periodic reassessments during their engagement.

Risks from cybersecurity threats have not materially affected, and are not currently anticipated to materially affect, our Company, including our business strategy, results of operations or financial condition. See, however, Item 1A. Risk Factors of this report for additional information regarding cybersecurity risks we face and their potential impact on our business strategy, results of operations and financial condition.

ITEM 3. LEGAL PROCEEDINGS

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Note 12—Commitments and Contingencies in Item 8. Financial Statements and Supplementary Data of this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Listing and Holders of Record

Shares of our Class A Common Stock are listed on the Nasdaq Global Select Market under the symbol "VNOM." There were five holders of record of our Class A Common Stock on February 21, 2025. There is no trading market for our Class B Common Stock; however, shares of our Class B Common Stock, together with an equal number of OpCo Units, are exchangeable for the same number of shares of our Class A Common Stock at the discretion of the holders under the terms and conditions of the applicable exchange agreement with such holders. There were four holders of record of our Class B Common Stock on February 21, 2025.

Cash Dividend Policy

Under our current dividend policy, we intend to pay a base dividend, as well as a variable dividend that takes into account capital returned to stockholders via our stock repurchase program. We currently intend to pay quarterly variable dividends of at least 75% of our available cash less the base dividend declared and the amount paid in stock repurchases as part of our buyback program for the applicable quarter.

Our available cash and the available cash of the Operating Company for each quarter is determined by our board of directors following the end of such quarter. We expect that our available cash will generally equal the Adjusted EBITDA (as defined below) attributable to us for the applicable quarter, less cash needed for income taxes payable, debt service, contractual obligations, fixed charges and reserves for future operating or capital needs that our board of directors deems necessary or appropriate, lease bonus income (net of applicable taxes), distribution equivalent rights payments and preferred distributions.

The percentage of cash available for distribution by the Operating Company to us pursuant to the distribution policy may change quarterly to enable the Operating Company to retain cash flow to help strengthen our balance sheet while also expanding the return of capital program through our stock repurchase program.

We are also required to pay a quarterly preferred dividend in respect of our Class B Common Stock in the aggregate amount of $20,000 per quarter. Other than the preferred dividend requirement, we are not required to pay dividends to our stockholders on a quarterly or other basis, and declaration of any other dividends in the future will be solely in the discretion of our board of directors.

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) attributable to us plus net income (loss) attributable to non-controlling interest ("net income (loss)") before interest expense, net, non-cash share-based compensation expense, depletion, non-cash (gain) loss on derivative instruments, (gain) loss on extinguishment of debt, if any, other non-cash operating expenses, other non-recurring expenses and provision for (benefit from) income taxes.

Repurchases of Equity Securities

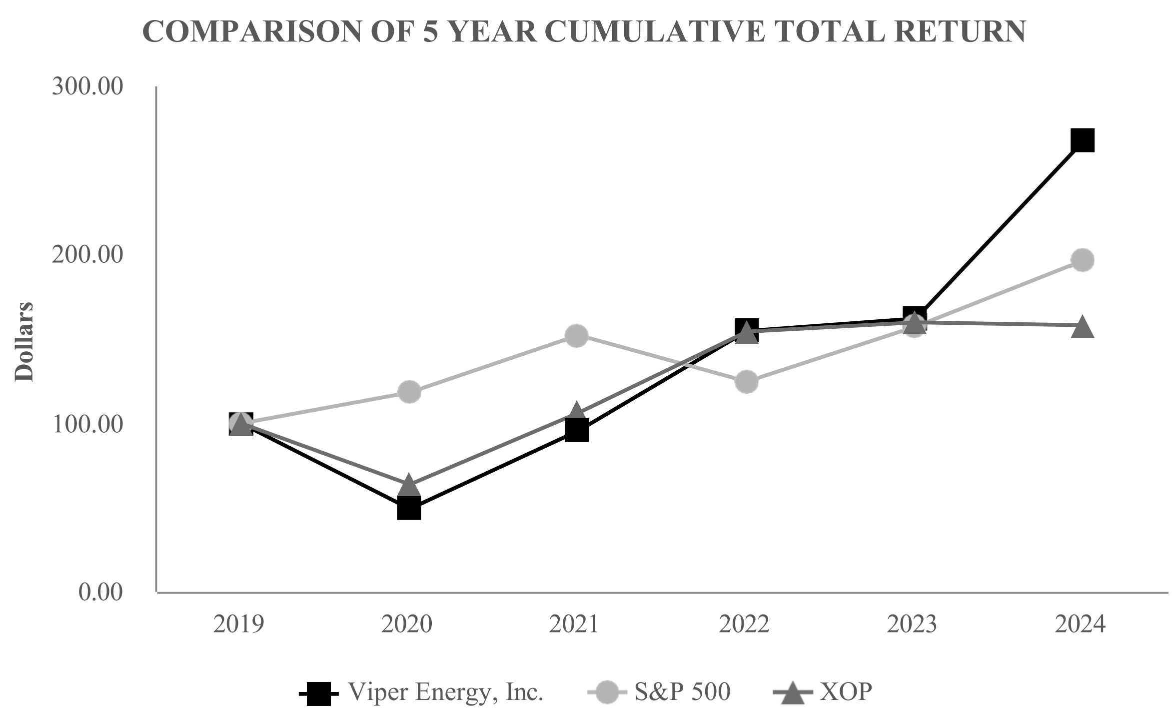
Our repurchase activity for shares of our Class A Common Stock for the three months ended December 31, 2024 was as follows:

Period	Total Number of Shares Purchased[(1)]	Average Price Paid Per Share[(3)]	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan[(2)(3)]
		(In thousands, except share amounts)		
October 1, 2024 - October 31, 2024	2,295	$ 45.11	—	$ 434,161
November 1, 2024 - November 30, 2024	—	$ —	—	$ 434,161
December 1, 2024 - December 31, 2024	—	$ —	—	$ 434,161
Total	2,295	$ 45.11	—	

(1) Includes 2,295 shares of Class A Common Stock repurchased from employees in order to satisfy tax withholding requirements. Such shares are cancelled and retired immediately upon repurchase.
(2) On July 26, 2022, the board of directors increased the authorization under our then-in-effect repurchase program from $250.0 million to $750.0 million. This repurchase program has no expiration date and remains subject to market conditions, applicable legal requirements, contractual obligations and other factors and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.
(3) All dollar amounts presented exclude such excise tax, as applicable.

Stock Performance Graph

The following performance graph includes a comparison of our cumulative total stockholder return over a five-year period with the cumulative total returns of the Standard & Poor's 500 Stock Index, or the S&P 500 Index, and the SPDR S&P Oil & Gas Exploration and Production ETF, or XOP Index. The graph assumes an investment of $100 on December 31, 2019, and that all dividends were reinvested.



	As of December 31,					
Calculated Values	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Viper Energy, Inc.	$100.00	$49.28	$95.64	$154.75	$162.12	$268.08
S&P 500	$100.00	$118.39	$152.34	$124.73	$157.47	$196.85
XOP	$100.00	$63.69	$106.21	$154.35	$159.83	$158.18

Recent Sales of Unregistered Securities

None.

ITEM 6. [RESERVED]

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto presented in Item 8. Financial Statements and Supplementary Data of this report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors discussed further in Item 1A. Risk Factors and Cautionary Statement Regarding Forward-Looking Statements of this report.

Overview

We are a publicly traded Delaware corporation focused on owning and acquiring mineral and royalty interests in oil and natural gas properties primarily in the Permian Basin. We operate in one reportable segment.

The following discussion includes a comparison of our results of operations, including changes in our operating income, and liquidity and capital resources for fiscal year 2024 and fiscal year 2023. A discussion of changes in our results of operations from fiscal year 2023 compared to fiscal year 2022 has been omitted from this report, but may be found in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of our Annual Report on Form 10-K for the fiscal year ended December 31, 2023, filed with the SEC on February 22, 2024, and is incorporated by reference in this report from such prior Annual Report on Form 10-K.

Recent Developments

2025 Transactions

Morita Ranches Acquisition

On February 14, 2025, we completed the Morita Ranches Acquisition for consideration consisting of approximately (i) $211.0 million in cash and (ii) 2.40 million OpCo Units together with an equal number of shares of Class B Common Stock to be issued to the Morita Ranches Equity Recipients, subject to certain transaction costs and post-closing adjustments. The mineral and royalty interests acquired in the Morita Ranches Acquisition represent approximately 1,691 net royalty acres located in the Permian Basin. We funded the cash consideration for the Morita Ranches Acquisition with cash on hand.

2025 Equity Offering

On February 3, 2025, we completed an underwritten public offering of approximately 28.34 million shares of our Class A Common Stock, which included approximately 3.70 million shares issued pursuant to an option to purchase additional shares of Class A Common Stock granted to the underwriters, at a price to the public of $44.50 per share for total net proceeds of approximately $1.2 billion, after the underwriters' discount and transaction costs (the "2025 Equity Offering"). We intend to use the proceeds from the 2025 Equity Offering to fund the cash consideration for the Pending 2025 Drop Down, if it closes, and will use the remaining proceeds for general corporate purposes. If the Pending 2025 Drop Down does not close, we will use the proceeds from the 2025 Equity Offering for general corporate purposes.

Pending 2025 Drop Down Transaction

On January 30, 2025, we and the Operating Company entered into a definitive equity purchase agreement with Endeavor and the Endeavor Subsidiaries, each of which is a subsidiary of Diamondback, to acquire the Endeavor Subsidiaries from Endeavor for consideration consisting of (i) $1.0 billion in cash and (ii) the issuance of approximately 69.63 million OpCo Units and an equivalent number of shares of our Class B Common Stock, in each case subject to customary closing adjustments, including, among other things, for net title benefits. The mineral and royalty interests acquired in the Pending 2025 Drop Down represent approximately 22,847 net royalty acres in the Permian Basin, 69% of which are operated by Diamondback. The Pending 2025 Drop Down is expected to close in the second quarter of 2025, subject to certain conditions discussed further in Note 13—Subsequent Events in Item 8. Financial Statements and Supplementary Data of this report.

See Note 13—Subsequent Events in Item 8. Financial Statements and Supplementary Data of this report for further information.

2024 Acquisitions and Divestitures Update

Tumbleweed Acquisitions

On October 1, 2024, we completed the TWR Acquisition for consideration consisting of approximately (i) $464.2 million in cash, including transaction costs and certain customary post-closing adjustments, (ii) 10.09 million OpCo Units to TWR IV, (iii) the TWR Class B Option, and (iv) contingent cash consideration of up to $41.0 million, payable in January of 2026, based on the WTI 2025 Average. The mineral and royalty interests acquired in the TWR Acquisition represent approximately 3,067 net royalty acres located primarily in the Permian Basin.

On September 3, 2024, we completed (i) the Q Acquisition, which consisted of approximately 406 net royalty acres primarily in the Permian Basin, for a purchase price of approximately $114.0 million in cash, including transaction costs and certain customary post-closing adjustments, and contingent cash consideration of up to $5.4 million payable in January of 2026, based on the WTI 2025 Average and (ii) the M Acquisition, which consisted of approximately 267 net royalty acres primarily in the Permian Basin, for a purchase price of approximately $76.1 million in cash, including transaction costs and certain customary post-closing adjustments, and contingent cash consideration of up to $3.6 million payable in January of 2026, based on the WTI 2025 Average.

Other Acquisitions

During the year ended December 31, 2024, we acquired, in individually insignificant transactions from unrelated third-party sellers, mineral and royalty interests representing 261 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $54.2 million, including customary closing adjustments.

Divestiture

In the second quarter of 2024, we divested all of our non-Permian assets for a purchase price of approximately $87.2 million, including transaction costs and customary post-closing adjustments. The divested properties consisted of approximately 2,713 net royalty acres with current production of approximately 450 BO/d.

After giving effect to the recently completed Morita Ranches Acquisition and the Pending 2025 Drop Down, our footprint of mineral and royalty interests totaled approximately 60,209 net royalty acres, approximately 59% of which are operated by Diamondback.

See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for further information.

2024 Equity Offering

On September 13, 2024, we completed an underwritten public offering of approximately 11.50 million shares of our Class A Common Stock, which included 1.50 million shares issued pursuant to an option to purchase additional shares of Class A Common Stock granted to the underwriters, at a price to the public of $42.50 per share for total net proceeds of approximately $475.9 million, after the underwriters' discount and transaction costs (the "2024 Equity Offering"). The proceeds from the 2024 Equity Offering were primarily used to fund the cash portion of the TWR Acquisition.

Diamondback Offering

On March 8, 2024, Diamondback completed an underwritten public offering in which it sold approximately 13.2 million shares of our Class A Common Stock (the "Diamondback Offering"). See Note 1—Organization and Basis of Presentation in Item 8. Financial Statements and Supplementary Data of this report for further information.

Commodity Prices and Certain Other Market Considerations

Prices for oil, natural gas and natural gas liquids are determined primarily by prevailing market conditions. Regional and worldwide economic activity, extreme weather conditions and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. OPEC and its non-OPEC allies, known collectively as OPEC+, continue to meet regularly to evaluate the state of global oil supply, demand and inventory levels and can heavily influence volatility in oil prices. During 2024, 2023 and 2022, WTI prices averaged $75.76, $77.60 and $94.33 per Bbl, respectively, and Henry Hub prices averaged $2.41, $2.66 and 6.54 per MMBtu, respectively. For additional information around risks related to commodity prices, see Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.

Based on 2024 commodity prices, industry conditions and the results of the quarterly ceiling tests, we were not required to record an impairment on our proved oil and natural gas interests during the year ended December 31, 2024. If commodity prices fall below current levels, we may be required to record impairments in future periods and such impairments could be material. Further, if commodity prices decrease, our production, proved reserves and cash flows may be adversely impacted. Our business may also be adversely impacted by any pipeline capacity and storage constraints.

Cash Distributions

On August 1, 2024, our board of directors approved increasing our annual base dividend to $1.20 per share of Class A Common Stock beginning with the dividend payable for the second quarter of 2024. On January 30, 2025, we declared a combined base and variable cash dividend of $0.65 per share of Class A Common Stock and $0.69 per OpCo Unit payable on March 13, 2025.

2025 Guidance

The following table presents our current estimates of certain financial and operating results for the first quarter of 2025:

	2025 Guidance
Q1 2025 net production - MBO/d	30.00 - 31.00
Q1 2025 net production - MBOE/d	54.00 - 56.00
Costs ($/BOE)	
Depletion	$12.25 - $12.75
Cash general and administrative expenses	$0.80 - $1.00
Non-cash share-based compensation	$0.10 - $0.20
Net interest expense	$2.50 - $3.00
Production and ad valorem taxes (% of revenue)	~7%
Cash tax rate (% of pre-tax income attributable to Viper Energy, Inc.)	20% - 22%
Q1 2025 cash taxes (In millions)(1)	$15.0 - $20.0

(1) Attributable to Viper Energy, Inc.

Production and Operational Update

As of December 31, 2024, there were 54 gross rigs operating on our mineral and royalty acreage, 10 of which are operated by Diamondback. We continue to deliver strong organic production growth on our legacy assets and successfully execute on our differentiated acquisition strategy.

The following table summarizes our gross well information as of December 31, 2024, unless otherwise specified:

	Diamondback Operated	Third-Party Operated	Total
Horizontal wells turned to production (fourth quarter 2024)(1):			
Gross wells	88	293	381
Net 100% royalty interest wells	5.6	2.5	8.1
Average percent net royalty interest	6.4 %	0.9 %	2.1 %
Horizontal wells turned to production (year ended December 31, 2024)(2):			
Gross wells	285	1,176	1,461
Net 100% royalty interest wells	16.0	11.9	27.9
Average percent net royalty interest	5.6 %	1.0 %	1.9 %
Horizontal producing well count:			
Gross wells	2,898	8,161	11,059
Net 100% royalty interest wells	156.3	104.1	260.4
Average percent net royalty interest	5.4 %	1.3 %	2.4 %
Horizontal active development well count(3):			
Gross wells	146	721	867
Net 100% royalty interest wells	6.0	8.1	14.1
Average percent net royalty interest	4.1 %	1.1 %	1.6 %
Line of sight wells(4):			
Gross wells	324	867	1,191
Net 100% royalty interest wells	10.1	13.8	23.9
Average percent net royalty interest	3.1 %	1.6 %	2.0 %

(1) Average lateral length of 10,818 feet.
(2) Average lateral length of 11,381 feet.
(3) The total 867 gross wells currently in the process of active development are those wells that have been spud and are expected to be turned to production within approximately the next six to eight months.
(4) The total 1,191 line-of-sight wells are those that are not currently in the process of active development, but for which Viper has reason to believe will be turned to production within approximately the next 15 to 18 months. The expected timing of these line-of-sight wells is based primarily on permitting by third-party operators or Diamondback’s current expected completion schedule. Existing permits or active development of our net royalty acreage does not ensure that those wells will be turned to production given the volatility in oil prices.

Results of Operations

Comparison of the Years Ended December 31, 2024 and 2023

For a discussion of the results of operations for the year ended December 31, 2023 as compared to the year ended December 31, 2022, please refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2023 (filed with the SEC on February 22, 2024), which is incorporated in this report by reference from such prior report on Form 10-K.

The following table summarizes our income and expenses for the periods indicated:

	Year Ended December 31,	
	2024	2023
	(In thousands)	
Operating income:		
Oil income	$ 750,243	$ 619,181
Natural gas income	14,813	30,953
Natural gas liquids income	88,520	66,976
Royalty income	853,576	717,110
Lease bonus income—related party	227	107,823
Lease bonus income	5,944	1,855
Other operating income	640	909
Total operating income	860,387	827,697
Costs and expenses:		
Production and ad valorem taxes	60,882	50,401
Depletion	214,412	146,118
General and administrative expenses—related party	10,541	3,696
General and administrative expenses	8,100	6,907
Other operating (income) expense	55	356
Total costs and expenses	293,990	207,478
Income (loss) from operations	566,397	620,219
Other income (expense):		
Interest expense, net	(73,848)	(47,392)
Gain (loss) on derivative instruments, net	11,386	(25,793)
Other income, net	—	259
Total other expense, net	(62,462)	(72,926)
Income (loss) before income taxes	503,935	547,293
Provision for (benefit from) income taxes	(99,711)	45,952
Net income (loss)	603,646	501,341
Net income (loss) attributable to non-controlling interest	244,401	301,253
Net income (loss) attributable to Viper Energy, Inc.	$ 359,245	$ 200,088

The following table summarizes our production data, average sales prices and average costs for the periods indicated:

	Year Ended December 31,	
	2024	2023
Production data:		
Oil (MBbls)	9,939	8,028
Natural gas (MMcf)	24,606	19,130
Natural gas liquids (MBbls)	4,181	3,108
Combined volumes (MBOE)(1)	18,221	14,324
Average daily oil volumes (BO/d)	27,156	21,995
Average daily combined volumes (BOE/d)	49,784	39,244
Average sales prices:		
Oil ($/Bbl)	$ 75.48	$ 77.13
Natural gas ($/Mcf)	$ 0.60	$ 1.62
Natural gas liquids ($/Bbl)	$ 21.17	$ 21.55
Combined ($/BOE)(2)	$ 46.85	$ 50.06
Oil, hedged ($/Bbl)(3)	$ 74.57	$ 76.05
Natural gas, hedged ($/Mcf)(3)	$ 0.85	$ 1.37
Natural gas liquids ($/Bbl)(3)	$ 21.17	$ 21.55
Combined price, hedged ($/BOE)(3)	$ 46.68	$ 49.13
Average costs ($/BOE):		
Production and ad valorem taxes	$ 3.34	$ 3.52
General and administrative - cash component	0.86	0.65
Total operating expense - cash	$ 4.20	$ 4.17
General and administrative - non-cash stock compensation expense	$ 0.16	$ 0.09
Interest expense, net	$ 4.05	$ 3.31
Depletion	$ 11.77	$ 10.20

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per one Bbl.

(2) Realized price net of all deducts for gathering, transportation and processing.

(3) Hedged prices reflect the impact of cash settlements on our matured commodity derivative transactions on our average sales prices.

Royalty Income. Our royalty income is a function of oil, natural gas and natural gas liquids production volumes sold and average prices received for those volumes.

Royalty income increased $136.5 million during the year ended December 31, 2024 compared to the same period in 2023. This net increase consisted of an additional $179.4 million in royalty income from the 27% growth in production, partially offset by a decrease of $42.9 million due to lower average oil, natural gas and natural gas liquids prices received from our production during 2024 compared to the same period in 2023.

Approximately 64% of the overall increase in production is attributable to the GRP Acquisition and approximately 12% is attributable to the Tumbleweed Acquisitions. The remainder of the growth comes from new wells added between periods. See Note 4—Acquisitions and Divestitures in Item 8. Financial Statements and Supplementary Data of this report for definition and further discussion of our acquisitions.

Lease Bonus Income—Related Party. Lease bonus income from Diamondback decreased $107.6 million during the year ended December 31, 2024 due to receiving payment for three new leases covering approximately 85 acres in Martin County Texas, compared to (i) one lease of $95.8 million in our Spanish Trail prospect in Midland County, Texas, (ii) nine other new leases in Martin, Midland, Pecos and Wheeler Counties; Texas, and (iii) two lease extensions in Martin County, Texas, in the same period in 2023.

Production and Ad Valorem Taxes. The following table presents production and ad valorem taxes for the periods indicated:

	Year Ended December 31,					
	2024			2023		
	Amount (In thousands)	Per BOE	Percentage of Royalty Income	Amount (In thousands)	Per BOE	Percentage of Royalty Income
Production taxes	$ 42,547	$ 2.33	5.0 %	$ 35,976	$ 2.51	5.0 %
Ad valorem taxes	18,335	1.01	2.1	14,425	1.01	2.0
Total production and ad valorem taxes	$ 60,882	$ 3.34	7.1 %	$ 50,401	$ 3.52	7.0 %

In general, production taxes are directly related to production revenues and are based upon current year commodity prices. Production taxes as a percentage of royalty income for the year ended December 31, 2024 remained consistent with 2023.

Ad valorem taxes are based, among other factors, on property values driven by prior year commodity prices. Ad valorem taxes for the year ended December 31, 2024 remained consistent with 2023 as a percentage of royalty income and on a per BOE basis.

Depletion. The increase in depletion expense of $68.3 million for the year ended December 31, 2024 compared to the same period in 2023 consisted primarily of (i) $39.7 million from growth in production volumes, and (ii) $28.6 million due to an increase in the depletion rate to $11.77 per BOE for the year ended December 31, 2024, resulting primarily from the addition of leasehold costs and reserves from the GRP Acquisition and the Tumbleweed Acquisitions compared to $10.20 per BOE for the same period in 2023.

General and Administrative Expenses. The following table shows general and administrative expenses for the periods presented:

	Year Ended December 31,	
	2024	2023
	(In thousands, except per BOE amounts)	
General and administrative expenses—related party	$ 10,541	$ 3,696
General and administrative expenses	8,100	6,907
General and administrative expenses	$ 18,641	$ 10,603
General and administrative expenses ($ per BOE)	$ 1.02	$ 0.74

The $8.0 million increase in general and administrative expenses for the year ended December 31, 2024 compared to 2023 consists of (i) a $6.8 million increase in expenses billed by Diamondback as discussed below, and (ii) a $1.2 million net increase of non-cash compensation related to unvested employee restricted stock units.

Prior to 2024, we reimbursed Diamondback a flat quarterly fee for management and administrative services provided to us by Diamondback. Beginning in 2024, Diamondback began billing us for estimated actual salary and benefit costs incurred for services provided to us by seconded employees under the services and secondment agreement.

Interest Expense, Net. Net interest expense increased by $26.5 million for the year ended December 31, 2024, compared to the same period in 2023. The increase primarily consisted of (i) approximately $23.7 million due to recording a full year of interest expense for our 2031 Notes, which were issued in October 2023, (ii) approximately $1.8 million in additional interest expense on our revolving credit facility, and (iii) other individually insignificant changes. See Note 6—Debt in Item 8. Financial Statements and Supplementary Data of this report for definition and additional discussion of our 2031 Notes.

Derivative Instruments. The following table shows the net gain (loss) on derivative instruments and the net cash receipts (payments) on derivatives for the periods presented:

	Year Ended December 31,	
	2024	2023
	(In thousands)	
Gain (loss) on derivative instruments	$ 11,386	$ (25,793)
Net cash receipts (payments) on derivatives	$ (2,978)	$ (13,319)

The change to a gain on derivative instruments from a loss on derivative instruments for the year ended December 31, 2024 compared to 2023 is primarily due to an increase in the differential between prices for Waha Hub and Henry Hub resulting in a gain on our natural gas basis swaps in the year ended December 31, 2024 compared to a loss in 2023. See Note 10—Derivatives in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of our open contracts at December 31, 2024.

Provision for (Benefit from) Income Taxes. We recorded an income tax benefit of $99.7 million and an income tax expense of $46.0 million for the years ended December 31, 2024 and 2023, respectively. This change is primarily due to the release of our remaining valuation allowance of $155.9 million during the fourth quarter of 2024. This was slightly offset by an increase in taxable income attributable to Viper Energy, Inc. in 2024. See Note 9—Income Taxes in Item 8. Financial Statements and Supplementary Data of this report for further details.

Net Income (Loss) Attributable to Non-controlling Interest. The $56.9 million decrease in net income attributable to non-controlling interest for the year ended December 31, 2024 compared to the same period in 2023 is primarily due to a reduction in Diamondback's ownership in the Operating Company following the completion of the Diamondback Offering and the 2024 Equity Offering in which Viper received additional OpCo Units from the Operating Company in exchange for the proceeds of the 2024 Equity Offering.

Liquidity and Capital Resources

Overview of Sources and Uses of Cash

As we pursue our business and financial strategy, we regularly consider which capital resources, including cash flow, equity and debt financings, are available to meet our future financial obligations and liquidity requirements. Our future ability to grow proved reserves will be highly dependent on the capital resources available to us. Our primary sources of liquidity have been cash flows from operations, proceeds from sales of non-core assets, equity and debt offerings and borrowings under the Operating Company's revolving credit facility. Our primary uses of cash have been dividends to our stockholders, Operating Company distributions to the holders of OpCo Units, repayments of debt, capital expenditures for the acquisition of our mineral and royalty interests in oil and natural gas properties, including the Tumbleweed Acquisitions and repurchases of our Class A Common Stock. At December 31, 2024, we had approximately $1.0 billion of liquidity consisting of $26.9 million in cash and cash equivalents and $989.0 million available under the Operating Company's revolving credit facility. As noted above in "—Recent Developments," in February 2025 we raised an additional $1.2 billion in net cash proceeds from the 2025 Equity Offering, which will be used to fund the cash portion of the Pending 2025 Drop Down, if it closes. If the Pending 2025 Drop Down does not close, then the $1.2 billion in net cash proceeds from the 2025 Equity Offering will be used for general corporate purposes. See further discussion of changes in our sources of cash in "—*Capital Resources*" below.

Our working capital requirements are supported by our cash and cash equivalents and the Operating Company's revolving credit facility. We may draw on the Operating Company's revolving credit facility to meet short-term cash requirements, or issue debt or equity securities as part of our longer-term liquidity and capital management program. Because of the alternatives available to us as discussed above, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term funding requirements including future acquisitions of mineral and royalty interests, dividends, debt service obligations, repayment of debt maturities, repurchases of our Class A Common Stock or any of our Notes, and any amounts that may ultimately be paid in connection with contingencies.

In order to mitigate volatility in oil and natural gas prices, we have entered into commodity derivative contracts as discussed further in Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk of this report.

Continued prolonged volatility in the capital, financial and/or credit markets due to the war in Ukraine, the Israel-Hamas War and other conflicts in the Middle East, and/or adverse macroeconomic conditions, including higher interest rates, global supply chain disruptions and actions taken by OPEC members and other exporting nations may limit our access to, or increase our cost of, capital or make capital unavailable on terms acceptable to us or at all. Although we expect that our sources of funding will be adequate to fund our short-term and long-term liquidity requirements, we cannot assure you that the needed capital will be available on acceptable terms or at all.

Cash Flows

The following table presents our cash flows for the period indicated:

	Year Ended December 31,	
	2024	2023
	(In thousands)	
Cash flow data:		
Net cash provided by (used in) operating activities	$ 619,608	$ 638,192
Net cash provided by (used in) investing activities	(608,573)	(908,365)
Net cash provided by (used in) financing activities	(10,053)	277,863
Net increase (decrease) in cash and cash equivalents	$ 982	$ 7,690

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which are the volatility of prices for oil and natural gas and the volumes of oil and natural gas sold by our producers. The decrease in net cash provided by operating activities during the year ended December 31, 2024 compared to the same period in 2023 was primarily driven by (i) a reduction in related party lease bonus income, (ii) an increase in cash paid for interest expense due to the issuance of our 2031 Notes in the fourth quarter of 2023, (iii) changes in our working capital accounts, (iv) an increase in cash costs for production and ad valorem taxes and payments to Diamondback related to the change in the Pre-Conversion reimbursement methodology contemplated by the services and secondment agreement beginning on January 1, 2024, and (v) an increase in cash paid for taxes. These decreases in cash flow were offset by (i) an increase in royalty income, and (ii) a decrease in cash paid for derivatives. See "—*Results of Operations*" above for further discussion of significant changes in our income and expenses.

Investing Activities

Net cash used in investing activities during the year ended December 31, 2024 primarily related to acquisitions of oil and natural gas interests from third parties, which includes $654.3 million in cash paid for the Tumbleweed Acquisitions, partially offset by proceeds of $87.7 million primarily from the divestiture of non-Permian oil and natural gas interests.

Net cash used in investing activities during the year ended December 31, 2023 primarily related to acquisitions of oil and natural gas interests from third parties, which includes $747.5 million in cash paid for the GRP Acquisition, and $74.5 million in cash paid for the acquisition of other oil and natural gas interests in the 2023 Drop Down.

Financing Activities

Net cash used in financing activities during the year ended December 31, 2024 was primarily attributable to $481.0 million of dividends paid to stockholders and the Operating Company's unitholders and net repayments of $2.0 million on the Operating Company's revolving credit facility, offset by proceeds of $475.9 million from the 2024 Equity Offering.

Net cash provided by financing activities for the year ended December 31, 2023 primarily resulted from (i) net proceeds from the 2031 Notes of $394.0 million, (ii) proceeds from the 2023 Viper Issuance of $200.0 million, and (iii) net borrowings of $111.0 million under the Operating Company's revolving credit facility. These cash inflows were partially offset by dividends paid to stockholders of $324.8 million and $95.2 million of Class A Common Stock repurchases. See Note 7—Stockholders' Equity in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of the 2023 Viper Issuance.

Capital Resources

The Operating Company's Revolving Credit Facility

On November 22, 2024, the Operating Company entered into a thirteenth amendment to the existing credit facility, which, (i) maintained the maximum credit amount of $2.0 billion, (ii) maintained the borrowing base of $1.3 billion, and (iii) increased the aggregate elected commitment amount from $850.0 million to $1.3 billion.

The Operating Company had $261.0 million in outstanding borrowings and $989.0 million of availability on its revolving credit facility at December 31, 2024.

As of December 31, 2024, the Operating Company was in compliance, and expects to be in compliance, with all financial maintenance covenants under its credit facility. See Note 6—Debt in Item 8. Financial Statements and Supplementary Data of this report for additional discussion of our outstanding debt at December 31, 2024.

Capital Requirements

Pending 2025 Drop Down

On January 30, 2025, in connection with the Pending 2025 Drop Down, we entered into a definitive equity purchase agreement with Endeavor and the Endeavor Subsidiaries, pursuant to which and subject to the terms and conditions of such equity purchase agreement, we are obligated to pay Diamondback $1.0 billion in cash at the closing of, and as part of the total consideration for, the Pending 2025 Drop Down, which is expected to close during the second quarter of 2025.

See Note 13—Subsequent Events in Item 8. Financial Statements and Supplementary Data of this report for additional information on the Pending 2025 Drop Down.

Senior Notes

At December 31, 2024, we have total principal payments due on our outstanding Notes of $430.4 million in 2027 and $400.0 million in 2031. Additionally, we have a remaining aggregate interest expense obligation of $275.9 million on the Notes with $52.6 million due in 2025, an aggregate of $105.3 million due for years 2026 to 2027, an aggregate of $59.0 million due for years 2028 to 2029, and $59.0 million due thereafter. The Notes are not subject to any mandatory redemption or sinking fund requirements. See Note 6—Debt in Item 8. Financial Statements and Supplementary Data of this report for further information on the Notes.

Repurchases of Securities

Under our current common stock repurchase program, the board of directors has authorized us to acquire up to $750.0 million of our Common Stock, excluding excise tax. As of December 31, 2024, $434.2 million remains available for use to repurchase shares under this repurchase program. See Note 7—Stockholders' Equity in Item 8. Financial Statements and Supplementary Data of this report for further discussion of the stock repurchase program.

We may also from time to time opportunistically repurchase some of the outstanding Notes in open market purchases or in privately negotiated transactions.

Cash Dividends

We paid a total of $481.0 million and $324.8 million in distributions or dividends, as applicable, on our common shares, OpCo Units and participating securities under the LTIP during 2024 and 2023, respectively.

The dividend for the fourth quarter of 2024 is $0.65 per share of Class A Common Stock and $0.69 per OpCo Unit, and in each case is payable on March 13, 2025 to eligible holders of record at the close of business on March 6, 2025. The dividend on our Class A Common Stock consists of a base quarterly dividend of $0.30 per share and a variable quarterly dividend of $0.35 per share. See Note 7—Stockholders' Equity in Item 8. Financial Statements and Supplementary Data of this report for further discussion of our dividends. We expect to continue paying quarterly cash dividends in respect of our common shares. Future base and variable dividends are not required and are at the discretion of the board of directors, who may change the dividend policies at any time.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP.

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated by our management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Accounting estimates are considered to be critical if (i) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (ii) the impact of the estimates and assumptions on financial condition or operating performance is material. We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We consider the following to be our most critical accounting estimates and have reviewed these critical accounting estimates with the Audit Committee of our Board of Directors.

Royalty Income and Revenue Recognition

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and natural gas liquids sales from third-party operators other than Diamondback may not be received for 30 to 90 days after the date production is delivered. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded based upon the Company's interest. Where available, historical actual data is used to calculate volume estimates for wells operated by third parties. If historical actual data is not available for these wells, engineering estimates are used to calculate expected volumes. As such, estimated volumes utilized in period end royalty income accruals are subject to revision as additional actual data becomes available and such revisions may have a material impact on our results of operations and our royalty income receivables. Pricing estimates are based upon actual prices realized in an area by adjusting the market price for the average basis differential from market on a basin-by-basin basis. We record the differences between our estimates and the actual amounts received for royalties from third parties in the month that payment is received from the producer. We have existing internal controls for our royalty income estimation process and related accruals, but actual third-party royalty income in future periods could differ materially from estimated amounts. At December 31, 2024, our accrual for third-party royalty income was approximately $102.8 million. Actual revenues received during 2024 for prior years' production from third parties were approximately $7.3 million, or 9%, higher than the amount accrued at December 31, 2023.

Oil and Natural Gas Accounting and Reserves

We account for oil and natural gas producing activities using the full cost method of accounting, which is dependent on the estimation of proved reserves to determine the rate at which we record depletion on our oil and natural gas properties and whether the value of our evaluated oil and natural gas properties is permanently impaired based on the quarterly full cost ceiling impairment test. Further, we utilize estimated proved reserves to assign fair value to acquired mineral and royalty interests. As such, we consider the estimation of proved reserves to be a critical accounting estimate.

Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Proved oil and natural gas reserve estimates and their associated future net cash flows were prepared by our internal reservoir engineers and audited by Ryder Scott, independent petroleum engineers, as of December 31, 2024, 2023 and 2022. The process of estimating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. Significant inputs included in the calculation of future net cash flows include anticipated production of proved reserves and other relevant data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time, and reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future depletion of capitalized costs and result in impairment of assets that may be material. No impairments were recorded on our proved oil and natural gas properties during the years ended December 31, 2024, 2023 and 2022. Based on the historical 12-month average trailing SEC prices for oil and natural gas throughout 2024 and into 2025, we are not currently projecting a full cost ceiling impairment in the first quarter of 2025. Any future impairment could be material to our consolidated financial statements.

Additionally, costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property (on an individual basis or as a group if properties are individually insignificant) at least annually for possible impairment. This assessment is subjective and includes consideration of the following factors, among others: (i) monitoring information available from third-party operators of our acreage for future drilling plans, (ii) the success of operators drilling on our acreage, (iii) the assignment of proved reserves, and (iv) current market prices for mineral acreage within our primary basins. At December 31, 2024, our unevaluated properties totaled $2.2 billion. We did not record any impairment on our unevaluated properties during the year ended December 31, 2024, but any such future impairment could be material to our consolidated financial statements.

Acquisitions of Mineral and Royalty Interests

Acquisitions of mineral and royalty interests are accounted for as asset acquisitions, whereby the purchase price and associated transaction costs are capitalized and allocated to the acquired mineral and royalty interests. The allocation is determined based on whether the interests acquired relate to proved or unproved oil and natural gas properties, utilizing the estimated fair value of proved reserves as of the date of acquisition. The valuation of proved reserves is based on a projection of future cash flows using objective future pricing assumptions and a discount rate consistent with our estimated cost of capital at the time of the acquisition.

Income Taxes

The amount of income taxes we record requires interpretations of complex rules and regulations of federal, state, and provincial tax jurisdictions. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities, and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized after considering all positive and negative evidence available concerning the realizability of our deferred tax assets. Positive evidence may include forecasts of future taxable income, assessment of future business assumptions and any applicable tax planning strategies available to the Company. Negative evidence may include losses in recent years, if any, or the projection of losses in future periods. Estimating future taxable income requires numerous judgments and assumptions, including projections of future operating conditions which may be impacted by volatile future prices for our oil, natural gas and natural gas production, the expected timing and quantity of future production volumes, and the impact of our commodity derivative instruments on our income. These assumptions are discussed further in the critical accounting estimates titled *"— Royalty Income and Revenue Recognition" and "— Oil and Natural Gas Accounting and Reserves."* Due to the impact these various assumptions and estimates can have on our estimates of taxable income, an estimate of the sensitivity to changes is not practicable.

In 2024, management's assessment of all available evidence, both positive and negative, supporting realizability of the Company's deferred tax assets as required by applicable accounting standards, resulted in recognition of a deferred income tax benefit of $149.1 million for an increase in the portion of the Company's deferred tax assets considered more likely than not to be realized. A variety of positive evidence was assessed. The original recording of the valuation allowance was precipitated by the impact of the COVID-19 pandemic, which resulted in a collapse of worldwide oil prices that adversely affected the Company's profitability and its ability to reliably forecast future commodity prices and the pattern of development of undeveloped reserves. Since that time, the Company has sustained continuous net income due in part to higher commodity prices resulting from strong and stable market conditions that have resumed in the four years since the onset of the pandemic. Further, the locations in which we operate have experienced a sustained and increasing pattern of development by a wide variety of operators, consistent with a resumption of more readily predictable development pattern for our properties. Along with price and market stabilization, the significant acquisitions completed by the Company, including the Tumbleweed Acquisitions, provide additional production capacity to generate future taxable income for utilization of our deferred tax assets. Based on these factors, the Company released its remaining valuation allowance on its deferred tax assets in the fourth quarter of 2024. As of December 31, 2024, the Company had a net deferred tax asset of $184.8 million.

The accruals for deferred tax assets and liabilities are often based on assumptions that are subject to a significant amount of judgment by management. These assumptions and judgments are reviewed and adjusted as facts and circumstances change. Material changes to our income tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.

Recent Accounting Pronouncements

See Note 2—Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data of this report for discussion of recent accounting pronouncements and a full listing of our significant accounting policies.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to the oil and natural gas production of our operators. Realized prices are driven primarily by the prevailing worldwide price for crude oil and prices for natural gas in the United States. Both crude oil and natural gas realized prices are also impacted by the quality of the product, supply and demand balances in local physical markets and the availability of transportation to demand centers. Pricing for oil and natural gas production has been historically volatile and unpredictable and the prices that our operators receive for production depend on many factors outside of our or their control, as discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Overview of Sources and Uses of Cash. We cannot predict events that may lead to future price volatility and the near term energy outlook remains subject to heightened levels of uncertainty.

We historically have used fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of our royalty income as discussed in Note 10—Derivatives in Item 8. Financial Statements and Supplementary Data of this report.

At December 31, 2024, we had a net asset derivative position related to our commodity price derivative contracts of $15.3 million. Utilizing actual derivative contractual volumes under our contracts as of December 31, 2024, a 10% increase in forward curves associated with the underlying commodity would have increased the net asset position by $0.8 million to approximately $16.1 million, while a 10% decrease in forward curves associated with the underlying commodity would not have changed our net asset position significantly. However, any cash derivative gain or loss may be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Credit Risk

We are subject to risk resulting from the concentration of royalty income in producing oil and natural gas properties and receivables with a limited number of several significant purchasers. For the year ended December 31, 2024, no purchaser accounted for more than 10% of our income. For the years ended December 31, 2023 and 2022, two purchasers accounted for more than 10% of our income, respectively. See Note 2—Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data of this report for further details. We do not require collateral and the failure or inability of our significant purchasers to meet their obligations to us due to their liquidity issues, bankruptcy, insolvency or liquidation may adversely affect our financial results. Volatility in the commodity pricing environment and macroeconomic conditions may enhance our purchaser credit risk.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under the Operating Company's revolving credit facility. The terms of the credit facility currently provide for interest on borrowings at a floating rate equal to (i) term SOFR plus 0.10% ("Adjusted Term SOFR"), or (ii) an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50%, and 1-month Adjusted Term SOFR plus 1.00%), in each case plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% per annum in the case of the alternative base rate and from 2.00% to 3.00% per annum in the case of Adjusted Term SOFR, in each case depending on the amount of the loans outstanding in relation to the commitment, which is calculated using the least of the maximum credit amount, the aggregate elected commitment amount and the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment. As of December 31, 2024, we had $261.0 million in outstanding borrowings. During the year ended December 31, 2024, the weighted average interest rate was 7.34%.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

(a) Documents included in this report:

1. Financial Statements

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's consolidated financial statements and related notes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Viper Energy, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Viper Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2024 and 2023, the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2024, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated February 26, 2025 expressed an unqualified opinion.

Basis for opinion
These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

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

Estimation of proved reserves as it relates to the calculation and recognition of depletion expense and the valuation of acquired reserves in connection with the mineral and royalty interests acquired in the Tumbleweed Acquisitions

As described further in Note 2 to the consolidated financial statements, the Company accounts for its oil and natural gas properties using the full cost method of accounting, which requires management to make estimates of proved reserve volumes and future revenues to calculate depletion expense. Additionally, as described in Note 4 to the consolidated financial statements, the Company acquired significant mineral and royalty interests during the year through the Tumbleweed Acquisitions. To estimate the volume of proved reserves and future revenues, management makes significant estimates and assumptions, including forecasting the timing and volumetric amounts of production and corresponding decline rate of producing properties associated with the operator’s development plan. In addition, the estimation of reserves is impacted by management’s judgments and estimates regarding the financial performance of wells to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions. For acquired reserves, management utilizes an estimated fair value pricing model in determining the corresponding value of reserves. We identified the estimation of proved reserves of oil and natural gas interests, including acquired proved reserves in the Tumbleweed Acquisitions, due to its impact on depletion expense and acquisition accounting, as a critical audit matter.

The principal considerations for our determination that the estimation of proved reserves is a critical audit matter are that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves, could have a significant impact on the measurement of depletion expense and the fair value of proved oil and natural gas interests. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of key controls relating to management's estimation of proved reserves for the purpose of calculating depletion expense and management's estimation of the fair value of the acquired oil and natural gas interests in the Tumbleweed Acquisitions.

- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and independent petroleum engineering specialists, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's reserve volumes, and read the year-end reserve report audited by the independent petroleum engineering specialists.

- Identified inputs and assumptions that were significant to the period end determination of proved reserve volumes and tested management's process of determining the significant inputs and assumptions, as follows:

    - Compared the estimated pricing and pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year;

    - Vouched, on a sample basis, the net revenue interests used in the reserve report to underlying land and division order records;

    - Assessed forecasted production estimates by (i) comparing prior year forecasted production amounts to current year actual results and (ii) comparing forecasted production amounts in the current year reserve report to the actual historical production amounts in the current year, in total and for a sample of individual wells;

    - We evaluated the Company's assessment of operators' development plans for proved undeveloped properties reflected in the reserve report and compared the Company's historical conversion rates to evaluate the likelihood of development related to the proved undeveloped properties; and

    - Applied analytical procedures on inputs to the reserve report by comparing to historical actual results and to the prior year reserve report.

- Identified inputs and assumptions that were significant to the estimated fair value of the acquired oil and natural gas interests in the Tumbleweed Acquisitions and tested management's process of determining the significant inputs and assumptions, as follows:

    - Evaluated the appropriateness of fair value pricing, including pricing differentials, used in the fair value reserve reports by comparing the pricing forecast to published product pricing as of the acquisitions closing dates and pricing differentials to actual historical realized pricing of the acquired properties;

    - Evaluated the appropriateness of the discount rate used in the fair value reserve reports of proved reserves by comparing to the Company's actual weighted average cost of capital;

    - Compared, on a sample basis, the net revenue interest used in the fair value reserve reports to the purchase and sale agreements or historical reserve reports;

    - Tested the accuracy of forecasted production estimates in the fair value reserve reports by comparing forecasted production amounts to the actual historical production amounts and to the forecasted production in the year-end reserve report for a sample of individual wells;

    - Applied analytical procedures on the fair value reserve reports' forecasted production by comparing to the prior year reserve reports' forecasted production and to the year-end reserve reports' forecasted production of the acquired proved properties; and

- ◦ Compared the unproved acreage value allocated to other recent acquisitions in the same or similar locations.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2013.

Oklahoma City, Oklahoma
February 26, 2025

Viper Energy, Inc.
Consolidated Balance Sheets

	December 31, 2024	December 31, 2023
	(In thousands, except share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 26,851	$ 25,869
Royalty income receivable (net of allowance for credit losses)	149,234	108,681
Royalty income receivable—related party	30,971	3,329
Income tax receivable	2,238	813
Derivative instruments	17,638	358
Prepaid expenses and other current assets	11,112	4,467
Total current assets	238,044	143,517
Property:		
Oil and natural gas interests, full cost method of accounting ($2,179,837 and $1,769,341 excluded from depletion at December 31, 2024 and December 31, 2023, respectively)	5,712,671	4,628,983
Land	5,688	5,688
Accumulated depletion and impairment	(1,080,764)	(866,352)
Property, net	4,637,595	3,768,319
Derivative instruments	—	92
Deferred income taxes (net of allowances)	185,235	56,656
Other assets	8,166	5,509
Total assets	$ 5,069,040	$ 3,974,093
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 85	$ 19
Accounts payable—related party	1,980	1,330
Accrued liabilities	42,272	27,021
Derivative instruments	2,323	2,961
Income taxes payable	2,034	1,925
Total current liabilities	48,694	33,256
Long-term debt, net	1,082,979	1,083,082
Derivative instruments	—	201
Other long-term liabilities	30,148	—
Total liabilities	1,161,821	1,116,539
Commitments and contingencies (Note 12)		
Stockholders' equity:		
Class A Common Stock, 0.000001 par value: 1,000,000,000 shares authorized; 102,977,142 and 86,144,273 shares issued and outstanding as of December 31, 2024 and December 31, 2023, respectively	—	—
Class B Common Stock, 0.000001 par value: 1,000,000,000 shares authorized; 85,431,453 and 90,709,946 shares issued and outstanding as of December 31, 2024 and December 31, 2023, respectively	—	—
Additional paid-in capital	1,568,560	1,031,078
Retained earnings (accumulated deficit)	118,444	(16,786)
Total Viper Energy, Inc. stockholders' equity	1,687,004	1,014,292
Non-controlling interest	2,220,215	1,843,262
Total equity	3,907,219	2,857,554
Total liabilities and stockholders' equity	$ 5,069,040	$ 3,974,093

See accompanying notes to consolidated financial statements.

Viper Energy, Inc.
Consolidated Statements of Operations

	Year Ended December 31,		
	2024	2023	2022
	(In thousands, except per share amounts)		
Operating income:			
Oil income	$ 750,243	$ 619,181	$ 667,281
Natural gas income	14,813	30,953	83,149
Natural gas liquids income	88,520	66,976	87,546
Royalty income	853,576	717,110	837,976
Lease bonus income—related party	227	107,823	23,367
Lease bonus income	5,944	1,855	4,424
Other operating income	640	909	700
Total operating income	860,387	827,697	866,467
Costs and expenses:			
Production and ad valorem taxes	60,882	50,401	56,372
Depletion	214,412	146,118	121,071
General and administrative expenses—related party	10,541	3,696	3,696
General and administrative expenses	8,100	6,907	4,846
Other operating (income) expense	55	356	—
Total costs and expenses	293,990	207,478	185,985
Income (loss) from operations	566,397	620,219	680,482
Other income (expense):			
Interest expense, net	(73,848)	(47,392)	(39,994)
Gain (loss) on derivative instruments, net	11,386	(25,793)	(18,138)
Other income, net	—	259	1
Total other expense, net	(62,462)	(72,926)	(58,131)
Income (loss) before income taxes	503,935	547,293	622,351
Provision for (benefit from) income taxes	(99,711)	45,952	(32,653)
Net income (loss)	603,646	501,341	655,004
Net income (loss) attributable to non-controlling interest	244,401	301,253	503,331
Net income (loss) attributable to Viper Energy, Inc.	$ 359,245	$ 200,088	$ 151,673
Net income (loss) attributable to common shares:			
Basic	$ 3.82	$ 2.69	$ 2.00
Diluted	$ 3.82	$ 2.69	$ 2.00
Weighted average number of common shares outstanding:			
Basic	93,932	74,176	75,612
Diluted	93,932	74,176	75,679

See accompanying notes to consolidated financial statements.

Viper Energy, Inc.
Consolidated Statement of Stockholders' Equity

	Limited Partners				General Partner	Non-Controlling Interest	
	Common Units	Amount	Class B Units	Amount	Amount	Amount	Total
				(In thousands)			
Balance at December 31, 2021	78,546	$ 813,161	90,710	$ 931	$ 729	$ 1,418,007	$ 2,232,828
Unit-based compensation	—	1,304	—	—	—	—	1,304
Vesting of restricted stock units	79	—	—	—	—	—	—
Distribution equivalent rights payments	—	(365)	—	—	—	—	(365)
Distributions to public	—	(182,470)	—	—	—	—	(182,470)
Distributions to Diamondback	—	(1,785)	—	(99)	—	(232,219)	(234,103)
Distributions to General Partner	—	—	—	—	(80)	—	(80)
Change in ownership of consolidated subsidiaries, net	—	58,253	—	—	—	(58,253)	—
Repurchased units as part of unit buyback	(5,395)	(150,593)	—	—	—	—	(150,593)
Net income (loss)	—	151,673	—	—	—	503,331	655,004
Balance at December 31, 2022	73,230	$ 689,178	90,710	$ 832	$ 649	$ 1,630,866	$ 2,321,525

	Limited Partners				General Partner	Common Stock[1]					
	Common Units	Amount	Class B Units	Amount	Amount	Class A Shares	Class B Shares	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
						(In thousands)					
Balance at December 31, 2022	73,230	$689,178	90,710	$ 832	$ 649	—	—	$ —	$ —	$1,630,866	$2,321,525
Conversion of Viper Energy Partnership Units to Viper Energy Inc. Common Shares	(78,126)	(937,468)	(90,710)	(757)	—	78,126	90,710	938,225	—	—	—
Liquidation of General Partner	—	—	—	—	(559)	—	—	(591)	—	—	(1,150)
Common shares/units issued for acquisition	—	—	—	—	—	9,018	—	254,600	—	—	254,600
Common shares/units issued to related party	7,215	200,000	—	—	—	—	—	—	—	—	200,000
Equity-based compensation	—	1,098	—	—	—	—	—	204	—	—	1,302
Vesting of restricted stock shares/units	73	—	—	—	—	—	—	—	—	—	—
Distribution equivalent rights payments	—	(163)	—	—	—	—	—	—	(48)	—	(211)
Dividends/distributions to shareholders	—	(84,018)	—	—	—	—	—	—	(44,548)	—	(128,566)
Dividends/distributions to Diamondback	—	(862)	—	(75)	—	—	—	(20)	(4,530)	(190,489)	(195,976)
Distributions to General Partner	—	—	—	—	(90)	—	—	—	—	—	(90)
Change in ownership of consolidated subsidiaries, net	—	31,668	—	—	—	—	—	(133,300)	—	101,632	—
Repurchases as part of share/unit buyback	(2,392)	(67,181)	—	—	—	(1,000)	—	(28,040)	—	—	(95,221)
Net income (loss)	—	167,748	—	—	—	—	—	—	32,340	301,253	501,341
Balance at December 31, 2023	—	$ —	—	$ —	$ —	86,144	90,710	$1,031,078	$ (16,786)	$1,843,262	$2,857,554

(1) The par values of the outstanding shares of Class A Common Stock and Class B Common Stock each round to zero at December 31, 2023.

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Consolidated Statement of Stockholders' Equity - (Continued)

	Common Stock[(1)]					
	Class A Shares	Class B Shares	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	(In thousands)					
Balance at December 31, 2023	86,144	90,710	$1,031,078	$ (16,786)	$1,843,262	$2,857,554
Common Stock converted in Diamondback Offering	5,279	(5,279)	—	—	—	—
Net proceeds from the issuance of Common Stock	11,500	—	475,906	—	—	475,906
Equity-based compensation	—	—	2,975	—	—	2,975
Issuance of shares upon vesting of equity awards	54	—	—	—	—	—
Cash paid for tax withholding on vested equity awards	—	—	(132)	—	—	(132)
OpCo Units issued for acquisition	—	—	—	—	468,346	468,346
Distribution equivalent rights payments	—	—	—	(393)	—	(393)
Dividends to stockholders	—	—	—	(219,072)	—	(219,072)
Dividends to Diamondback	—	—	20	(4,550)	(249,686)	(254,216)
Dividends to other non-controlling interest	—	—	—	—	(7,368)	(7,368)
Change in ownership of consolidated subsidiaries, net	—	—	58,713	—	(78,740)	(20,027)
Net income (loss)	—	—	—	359,245	244,401	603,646
Balance at December 31, 2024	102,977	85,431	$1,568,560	$ 118,444	$2,220,215	$3,907,219

(1) The par values of the outstanding shares of Class A Common Stock and Class B Common Stock each round to zero during the periods presented.

See accompanying notes to consolidated financial statements.

Viper Energy, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2024	2023	2022
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 603,646	$ 501,341	$ 655,004
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for (benefit from) deferred income taxes	(149,085)	(7,000)	(49,656)
Depletion	214,412	146,118	121,071
(Gain) loss on derivative instruments, net	(11,386)	25,793	18,138
Net cash receipts (payments) on derivatives	(2,978)	(13,319)	(31,319)
Other	6,197	3,442	5,070
Changes in operating assets and liabilities:			
Royalty income receivable	(13,249)	(27,379)	(13,089)
Royalty income receivable—related party	(27,642)	2,931	(4,116)
Accounts payable and accrued liabilities	7,002	6,311	151
Accounts payable—related party	651	1,024	306
Income taxes payable	109	1,014	440
Other	(8,069)	(2,084)	(2,204)
Net cash provided by (used in) operating activities	619,608	638,192	699,796
Cash flows from investing activities:			
Acquisitions of oil and natural gas interests—related party	—	(75,073)	—
Acquisitions of oil and natural gas interests	(696,242)	(830,128)	(64,131)
Proceeds from sale of oil and natural gas interests	87,669	(3,164)	111,702
Net cash provided by (used in) investing activities	(608,573)	(908,365)	47,571
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	842,000	573,000	272,000
Repayment on credit facility	(844,000)	(462,000)	(424,000)
Proceeds from Notes	—	400,000	—
Repayment of Notes	—	—	(48,963)
Net proceeds from public offering	475,906	—	—
Proceeds from public offering to Diamondback	—	200,000	—
Repurchased shares/units under buyback program	—	(95,221)	(150,593)
Dividends/distributions to stockholders	(219,465)	(128,777)	(182,835)
Dividends/distributions to Diamondback	(254,216)	(195,976)	(234,103)
Dividends to other non-controlling interest	(7,368)	—	—
Other	(2,910)	(13,163)	(142)
Net cash provided by (used in) financing activities	(10,053)	277,863	(768,636)
Net increase (decrease) in cash and cash equivalents	982	7,690	(21,269)
Cash, cash equivalents and restricted cash at beginning of period	25,869	18,179	39,448
Cash, cash equivalents and restricted cash at end of period	$ 26,851	$ 25,869	$ 18,179
Supplemental disclosure of cash flow information:			
Interest paid	$ (73,860)	$ (40,187)	$ (36,868)
Cash (paid) received for income taxes	$ (56,125)	$ (51,345)	$ (16,990)
Supplemental disclosure of non—cash transactions:			
Class A Common Stock issued for acquisition	$ —	$ 254,600	$ —
OpCo Units issued for acquisition	$ 468,346	$ —	$ —

See accompanying notes to consolidated financial statements.

Viper Energy, Inc.
Notes to Consolidated Financial Statements

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Viper Energy, Inc. (the “Company”) is a publicly traded Delaware corporation focused on owning and acquiring mineral interests and royalty interests in oil and natural gas properties primarily in the Permian Basin. As of December 31, 2024, the Company owned approximately 52% of units representing limited liability company interests (“OpCo Units”) in its operating subsidiary Viper Energy Partners LLC (the “Operating Company”) and was the managing member of the Operating Company.

Prior to March 8, 2024, the Company was a “controlled company” under the rules of the Nasdaq Stock Market LLC (the “Nasdaq Rules”). On March 8, 2024, the Company’s parent, Diamondback, completed an underwritten public offering in which it sold approximately 13.2 million shares of the Company’s Class A Common Stock (the “Diamondback Offering”). Following the Diamondback Offering, Diamondback owned no shares of the Company’s Class A Common Stock and owned 85,431,453 shares of the Company’s Class B Common Stock, reducing its beneficial ownership to less than 50% of the Company’s total Common Stock outstanding. As such, the Company ceased to be a “controlled company” under the Nasdaq Rules. Prior to the Diamondback Offering, the Company’s board of directors had a majority of independent directors and a standing audit committee comprised of all independent directors but had elected to take advantage of certain exemptions from corporate governance requirements applicable to controlled companies under the Nasdaq Rules and, until March 8, 2024, did not have a compensation committee or a committee of independent directors that selects director nominees.

Effective as of March 8, 2024, the Company’s board of directors formed (i) the compensation committee for purposes of making certain executive and other compensation decisions, and (ii) the nominating and corporate governance committee for purposes of making certain nominating and corporate governance decisions, with each such committee’s rights and obligations being subject to the terms and conditions of (x) the Company’s certificate of incorporation, (y) such committee’s charter as adopted by the board, and (z) the services and secondment agreement, dated as of November 2, 2023, pursuant to which Diamondback provides personnel and general and administrative services to us, including the services of the executive officers and other employees, substantially in the same manner as those provided to the Company by the former General Partner prior to the Conversion.

As of December 31, 2024, Diamondback beneficially owned approximately 45% of the outstanding voting power of the Company’s capital stock.

Conversion into Corporation

Effective November 13, 2023 (the “Effective Time”), Viper Energy Partners LP (the “Partnership”) converted from a publicly traded Delaware limited partnership to a Delaware corporation pursuant to a plan of conversion (the “Conversion”) and changed names from Viper Energy Partners LP to Viper Energy, Inc. Additionally, the certificate of incorporation and the bylaws of Viper Energy, Inc. became effective. This report includes the results for the Partnership prior to the Conversion and the Company following the Conversion. References to the “Company” refer to (i) Viper Energy, Inc. and its consolidated subsidiaries following the Conversion, and (ii) the Partnership and its consolidated subsidiaries prior to the Conversion. References to shares or per share amounts prior to the Conversion refer to units or per unit amounts. Unless otherwise noted, all references to shares or per share amounts following the Conversion refer to shares or per share amounts of Common Stock, as defined in the paragraph below. References to dividends prior to the Conversion refer to distributions. There are no tax impacts resulting from the Conversion as the Partnership was treated as a corporation for tax purposes.

At the Effective Time, (i) each common unit representing limited partnership interest in the Partnership issued and outstanding immediately prior to the Effective Time was converted, on a unit-for-unit basis, into one issued and outstanding, fully paid and nonassessable share of Class A Common Stock, $0.000001 par value per share (“Class A Common Stock”), of the Company, (ii) each Class B unit representing limited partnership interest in the Partnership issued and outstanding immediately prior to the Effective Time was converted, on a unit-for-unit basis, into one issued and outstanding, fully paid and nonassessable share of Class B Common Stock, $0.000001 par value per share, of the Company (“Class B Common Stock” and, together with Class A Common Stock, “Common Stock”), and (iii) the general partner interest issued and outstanding immediately prior to the Effective Time (100% owned by the General Partner) was cancelled and was no longer outstanding. At the Effective Time, as a result of the Conversion, holders of common units became holders of Class A Common Stock and holders of Class B units became holders of Class B Common Stock. Similar to Class B units before the Conversion, each share of Class B Common Stock is exchangeable, at the discretion of the holders of Class B Common Stock, together with one unit of the Operating Company, into one share of Class A Common Stock post-Conversion. Holders of Class B Common Stock have the same preferred dividend and liquidation preference rights as those provided to holders of Class B units under the Partnership Agreement. At the Effective Time, Diamondback Energy, Inc. (“Diamondback”) and its wholly owned subsidiary Diamondback E&P LLC were the only holders of the Class B Common Stock and collectively owned approximately 56% of the outstanding shares of Common Stock.

At the Effective Time, the Certificate of Incorporation and Bylaws of the Company generally provided stockholders of the Company with substantially the same or greater rights and substantially the same or lesser obligations, as those that limited partners had in the Partnership Agreement. Previously, limited partners were not generally entitled to vote with respect to governance of the Partnership, except for those few matters set forth in the Partnership Agreement. Following the Conversion, except as otherwise expressly provided in the Certificate of Incorporation, the holders of Common Stock are entitled to vote on all matters on which stockholders of a corporation are generally entitled to vote on under the DGCL, including the election of the board of directors of the Company.

Diamondback continues to provide personnel and general and administrative services to the Company, including the services of the executive officers and other employees, pursuant to the services and secondment agreement in a similar manner as Diamondback previously provided to the General Partner. In addition, for so long as Diamondback and any of its subsidiaries collectively beneficially own at least 25% of the outstanding Common Stock of the Company, (i) Diamondback will have the right to designate up to three persons to serve as directors of the Company, and (ii) the board of directors of the Company may not appoint any person other than a Diamondback seconded employee as an executive officer of the Company unless such appointment is approved, in advance, by either (x) Diamondback (which approval may not be unreasonably withheld or conditioned), or (y) the affirmative vote of the holders of at least 80% of the voting power of the capital stock of the Company. Currently, there are two Diamondback designees to the board of directors of the Company—Travis Stice and Kaes Van’t Hof.

Basis of Presentation

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with accounting principles generally accepted in the United States (“GAAP”). All material intercompany balances and transactions are eliminated in consolidation. The Company reports its operations in one reportable segment.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had no effect on the previously reported total assets, total liabilities, stockholders’ equity, results of operations or cash flows.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities as of the date of the financial statements.

Making accurate estimates and assumptions is particularly difficult in the oil and natural gas industry given the challenges resulting from volatility in oil and natural gas prices. For instance, the war in Ukraine, the Israel-Hamas War and other conflicts in the Middle East, higher interest rates, global supply chain disruptions, and recent measures to combat persistent inflation and instability in the financial sector have contributed to recent pricing and economic volatility. The financial results of companies in the oil and natural gas industry have been and may continue to be impacted materially as a result of changing market conditions. Such circumstances generally increase uncertainty in the Company’s accounting estimates, particularly those involving financial forecasts.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in each particular circumstance. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas interests, estimates of third-party operated royalty income related to expected sales volumes and prices, the recoverability of costs of unevaluated properties, the fair value determination of assets and liabilities, including those acquired by the Company, fair value estimates of commodity derivatives and estimates of income taxes, including deferred tax valuation allowances.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and include all highly liquid investments purchased with a maturity of three months or less and money market funds. 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.

Royalty Income Receivable

Royalty income receivables consist of receivables for sales of oil, natural gas and natural gas liquids made by the Company's third-party operators and Diamondback to third-party purchasers. The operators remit payment for production directly to the Company. Most payments for production are received within three months after the production date. Payments on new wells added organically or through acquisition may be further delayed due to title opinion work which is required to be completed by the operator before payments are released.

Royalty income receivables are stated at amounts due from purchasers, net of an allowance for expected losses as estimated by the Company when collection is deemed doubtful. Royalty income receivables outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance utilizing the loss-rate method, which considers a number of factors, including the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, and the condition of the general economy and the industry as a whole. The Company writes off specific royalty income receivables when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for expected losses. At December 31, 2024 and December 31, 2023, the Company's allowance for expected losses was immaterial.

Derivative Instruments

The Company is required to recognize its derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

Revenue from Contracts with Customers

Royalty income represents the right to receive revenues from oil, natural gas and natural gas liquids sales obtained by the operator of the wells in which the Company owns a royalty interest. Royalty income is recognized at the point control of the product is transferred to the purchaser. Virtually all of the pricing provisions in the Company's contracts are tied to a market index.

Royalty income from oil, natural gas and natural gas liquids sales

The Company's oil, natural gas and natural gas liquids sales contracts are generally structured whereby the operator of the properties in which the Company owns a royalty interest sells the Company's proportionate share of oil, natural gas and natural gas liquids production to the purchaser and the Company collects its percentage royalty based on the revenue generated. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the wellhead or at the gas processing facility based on the Company's percentage ownership share of the revenue, net of any deductions for gathering and transportation.

Transaction price allocated to remaining performance obligations

The Company’s right to royalty income does not originate until production occurs and, therefore, is not considered to exist beyond each day’s production. Therefore, there are no remaining performance obligations under any of the Company’s royalty income contracts.

Contract balances

Under the Company’s royalty income contracts, it generally has the right to receive its interest in the gross proceeds collected by the producer from third-party purchasers of the Company’s production once production has occurred, at which point payment is unconditional. Accordingly, the Company’s royalty income contracts do not give rise to contract assets or liabilities under Accounting Standards Codification 606.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and natural gas liquids sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of royalty income to be received based upon the Company’s interest. The Company records the differences between its estimates and the actual amounts received for royalties in the month that payment is received from the producer. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. The Company believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition costs are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas. At December 31, 2024 and 2023, the Company’s oil and natural gas properties consist solely of mineral interests in oil and natural gas properties.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $11.77, $10.20 and $9.86 for the years ended December 31, 2024, 2023 and 2022, respectively. Depletion for oil and natural gas properties was $214.4 million, $146.1 million and $121.1 million for the years ended December 31, 2024, 2023 and 2022, respectively.

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 proved oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized oil and natural gas interests net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (ii) the cost of properties not being amortized, if any, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash write-down is required. See Note 5—Oil and Natural Gas Interests for additional discussion of the Company’s oil and natural gas properties.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property at least annually for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent of the operator to drill; remaining lease term with the current operator; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $18.3 million and $15.5 million, and accumulated amortization of those costs over the term of the credit facility of $11.3 million and $10.0 million as of December 31, 2024, and 2023, respectively.

Long-term debt includes capitalized costs related to the Company's 5.375% senior notes due 2027 and 7.375% senior notes due 2031 (collectively, the "Notes"). The costs associated with the Notes are being netted against the Notes' balances and amortized over the term of the Notes using the effective interest method. See Note 6—Debt for further details.

Related Party Transactions

Royalty Income Receivable

As of December 31, 2024 and December 31, 2023, Diamondback, either directly or through its consolidated subsidiaries, owed the Company $31.0 million and $3.3 million, respectively, for royalty income received from third parties for the Company's production, which had not yet been remitted to the Company.

Lease Bonus Income

During the year ended December 31, 2024, Diamondback E&P LLC paid the Operating Company $0.2 million of lease bonus income primarily related to new leases in the Midland Basin. During the year ended December 31, 2023, Diamondback E&P LLC paid the Operating Company $107.8 million of lease bonus income, which includes a lease bonus payment of $95.8 million from a lease agreement with a subsidiary of Diamondback covering certain Permian Basin acreage on terms substantially identical to the Operating Company's other lease arrangements with Diamondback. This transaction was considered and approved by the conflicts committee of the board of directors. During the year ended December 31, 2022, Diamondback, either directly or through its consolidated subsidiaries, paid the Company $23.4 million of lease bonus income primarily related to lease ratification and certain leases acquired in 2021.

Other Related Party Transactions

See Note 4—Acquisitions and Divestitures and Note 13—Subsequent Events for significant related party acquisitions of oil and natural gas interests.

See Note 7—Stockholders' Equity for further details regarding equity transactions with related parties.

All other related party transactions with Diamondback or its affiliates have been stated on the face of the consolidated financial statements or were insignificant for the years ended December 31, 2024, 2023 and 2022, respectively.

Accrued Liabilities

The Company's accrued liabilities are financial instruments for which the carrying value approximates fair value.

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

Accrued liabilities consist of the following as of the dates indicated:

	December 31,	
	2024	2023
	(In thousands)	
Interest payable	$ 9,911	$ 11,036
Ad valorem taxes payable	19,813	13,299
Derivatives instruments payable	1,177	1,279
Acquisition adjustment accrual	8,627	35
Other	2,744	1,372
Total accrued liabilities	$ 42,272	$ 27,021

Concentrations

The Company is subject to risk resulting from the concentration of the Company's royalty income in producing oil and natural gas properties and receivables with several significant purchasers. For the year ended December 31, 2024, no purchaser accounted for more than 10% of royalty income. For the year ended December 31, 2023, two purchasers each accounted for more than 10% of royalty income: Vitol Midstream Pipeline LLC (16%) and DK Trading and Supply LLC (15%). For the year ended December 31, 2022, two purchasers each accounted for more than 10% of royalty income: Shell Trading (US) Company (14%) and Vitol Midstream Pipeline LLC (14%). The Company does not require collateral and does not believe the loss of any single purchaser would materially impact the Company's operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities, and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2024, 2023 and 2022, there were no interest or penalties associated with uncertain tax positions recognized in the Company's consolidated financial statements. See Note 9—Income Taxes for further details.

Non-controlling Interest

Non-controlling interest in the accompanying consolidated financial statements represents Diamondback's ownership in the net assets of the Operating Company. When Diamondback's relative ownership interest in the Operating Company changes, adjustments to non-controlling interest and stockholders' equity, tax effected, will occur. Because these changes in the Company's ownership interest in the Operating Company did not result in a change of control, the transactions were accounted for as equity transactions under ASC Topic 810, "Consolidation." This guidance requires that any differences between the carrying value of the Company's basis in the Operating Company and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. See Note 7—Stockholders' Equity for further discussion of changes in ownership interest.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In November 2023, the FASB issued ASU 2023-07, "Segment Reporting (Topic 280) – Improvements to Reportable Segment Disclosures," which updates reportable segment disclosure requirements primarily through enhanced disclosures about significant segment expenses and information used to assess segment performance. The amendments are effective for fiscal years beginning after December 15, 2023, and for interim periods within fiscal years beginning after December 15, 2024. The amendments should be applied retrospectively to all prior periods presented in the financial statements. Adoption of the update did not impact the Company's financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In December 2023, the FASB issued ASU 2023-09, "Income Taxes (Topic 740) – Improvements to Income Tax Disclosures," which requires that certain information in a reporting entity's tax rate reconciliation be disaggregated, and provides additional requirements regarding income taxes paid. The amendments are effective for annual periods beginning after December 15, 2024, with early adoption permitted, and should be applied either prospectively or retrospectively. Management is currently evaluating this ASU to determine its impact on the Company's disclosures. Adoption of the update will not impact the Company's financial position, results of operations or liquidity.

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," which requires additional disclosure about specified categories of expenses included in relevant expense captions presented on the income statement. The amendments are effective for annual periods beginning after December 15, 2026, and for interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. The amendments may be applied either prospectively or retrospectively. Management is currently evaluating this ASU to determine its impact on the Company's disclosures. Adoption of the update will not impact the Company's financial position, results of operations or liquidity.

The Company considers the applicability and impact of all ASUs. ASUs not discussed above were assessed and determined to be either not applicable, previously disclosed, or not material upon adoption.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Royalty income represents the right to receive revenues from oil, natural gas and natural gas liquids sales obtained from third-party purchasers by the operator of the wells in which the Company owns a royalty interest. Royalty income is recognized at the point control of the product is transferred to the purchaser at the wellhead or at the gas processing facility based on the Company's percentage ownership share of the revenue, net of any deductions for gathering and transportation. Virtually all of the pricing provisions in the Company's contracts are tied to a market index.

For the years ended December 31, 2024, 2023 and 2022, any revenues recognized in the current reporting period for performance obligations satisfied in prior reporting periods were not material.

The following tables disaggregate the Company's revenue from oil, natural gas and natural gas liquids by revenue generated from production on properties operated by Diamondback and revenue generated from production on properties operated by third parties:

	Year Ended December 31, 2024		
	Revenue Generated from Diamondback Operated Properties	Revenue Generated from Third-Party Operated Properties	Total
		(In thousands)	
Oil income	$ 398,010	$ 352,233	$ 750,243
Natural gas income	9,734	5,079	14,813
Natural gas liquids income	50,784	37,736	88,520
Total royalty income	$ 458,528	$ 395,048	$ 853,576

	Year Ended December 31, 2023		
	Revenue Generated from Diamondback Operated Properties	Revenue Generated from Third-Party Operated Properties	Total
	(In thousands)		
Oil income	$ 376,961	$ 242,220	$ 619,181
Natural gas income	16,040	14,913	30,953
Natural gas liquids income	42,131	24,845	66,976
Total royalty income	$ 435,132	$ 281,978	$ 717,110

	Year Ended December 31, 2022		
	Revenue Generated from Diamondback Operated Properties	Revenue Generated from Third-Party Operated Properties	Total
	(In thousands)		
Oil income	$ 397,282	$ 269,999	$ 667,281
Natural gas income	44,232	38,917	83,149
Natural gas liquids income	56,382	31,164	87,546
Total royalty income	$ 497,896	$ 340,080	$ 837,976

4. ACQUISITIONS AND DIVESTITURES

2024 Activity

Acquisitions

Tumbleweed Acquisitions

In September and October of 2024, the Company completed a series of related acquisitions including the TWR Acquisition, the Q Acquisition and the M Acquisition, collectively the ("Tumbleweed Acquisitions") as defined and discussed below.

TWR Acquisition

On October 1, 2024, (the "TWR Closing Date"), the Company acquired all of the issued and outstanding equity interests in TWR IV, LLC and TWR IV SellCo, LLC from Tumbleweed Royalty IV, LLC ("TWR IV") and TWR IV SellCo Parent, LLC (the "TWR Acquisition"), pursuant to a definitive purchase and sale agreement for consideration consisting of approximately (i) $464.2 million in cash, including transaction costs and certain customary post-closing adjustments, (ii) 10.09 million OpCo Units to TWR IV, (iii) an option (the "TWR Class B Option") granted to TWR IV to acquire up to 10.09 million shares of the Company's Class B Common Stock, and (iv) contingent cash consideration of up to $41.0 million, payable in January of 2026, based on the average price of WTI sweet crude oil prompt month futures contracts for the calendar year 2025 (the "WTI 2025 Average"). The contingent cash consideration payment will be (i) $16.4 million if the WTI 2025 Average is between $60.00 and $65.00, (ii) $24.6 million if the WTI 2025 Average is between $65.00 and $75.00, or (iii) $41.0 million if the WTI 2025 Average is greater than $75.00. The Company recorded the contingent cash consideration at its fair value of $21.3 million on the TWR Closing Date (the "TWR Contingent Liability"). Additionally, at the closing of the TWR Acquisition, the Company assumed from TWR IV a royalty income receivable of approximately $24.3 million.

TWR IV can exchange some or all of the OpCo Units received for an equal number of shares of Class A Common Stock upon expiration of a six month lockup period, and any OpCo Units so exchanged will reduce the number of shares of Class B Common Stock subject to the TWR Class B Option. The mineral and royalty interests acquired in the TWR Acquisition represent approximately 3,067 net royalty acres located primarily in the Permian Basin. The Company funded the cash consideration for the TWR Acquisition through a combination of cash on hand, borrowings under the Operating Company's revolving credit facility and proceeds from the 2024 Equity Offering, as defined and discussed in Note 7—Stockholders' Equity.

Q Acquisition

On September 3, 2024 (the “Q Closing Date”), the Company acquired all of the issued and outstanding equity interests in Tumbleweed-Q Royalties, LLC (the “Q Acquisition”), pursuant to a definitive purchase and sale agreement for consideration consisting of (i) approximately $114.0 million in cash, including transaction costs and certain customary post-closing adjustments, and (ii) contingent cash consideration of up to $5.4 million, payable in January of 2026, based on the WTI 2025 Average. The contingent cash consideration payment will be (i) $2.2 million if the WTI 2025 Average is between $60.00 and $65.00, (ii) $3.2 million if the WTI 2025 Average is between $65.00 and $75.00, or (iii) $5.4 million if the WTI 2025 Average is greater than $75.00. The Company recorded the contingent cash consideration at its fair value of $2.9 million on the Q Closing Date (the “Q Contingent Liability”). The mineral and royalty interests acquired in the Q Acquisition represent approximately 406 net royalty acres located primarily in the Permian Basin. The cash consideration for the Q Acquisition was funded through a combination of cash on hand and borrowings under the Operating Company’s revolving credit facility.

M Acquisition

On September 3, 2024 (the “M Closing Date”), the Company acquired all of the issued and outstanding equity interests in MC TWR Royalties, LP and MC TWR Intermediate, LLC (the “M Acquisition”), pursuant to a definitive purchase and sale agreement for consideration consisting of (i) approximately $76.1 million in cash, including transaction costs and certain customary post-closing adjustments, and (ii) contingent cash consideration of up to $3.6 million, payable in January of 2026, based on the WTI 2025 Average. The contingent cash consideration payment will be (i) $1.4 million if the WTI 2025 Average is between $60.00 and $65.00, (ii) $2.2 million if the WTI 2025 Average is between $65.00 and $75.00, or (iii) $3.6 million if the WTI 2025 Average is greater than $75.00. The Company recorded the contingent cash consideration at its fair value of $1.9 million on the M Closing Date (the “M Contingent Liability”). The mineral and royalty interests acquired in the M Acquisition represent approximately 267 net royalty acres located primarily in the Permian Basin. The cash consideration for the M Acquisition was funded through a combination of cash on hand and borrowings under the Operating Company’s revolving credit facility.

At December 31, 2024, the aggregate estimated fair value of the Q Contingent Liability, the M Contingent Liability and the TWR Contingent Liability, (collectively, the “2026 WTI Contingent Liability“) was $29.8 million. See Note 10—Derivatives and Note 11—Fair Value Measurements for further discussion of the fair value of the 2026 WTI Contingent Liability.

Other Acquisitions

Additionally during the year ended December 31, 2024 the Company acquired, in individually insignificant transactions from unrelated third-party sellers, mineral and royalty interests representing 261 net royalty acres in the Permian Basin for an aggregate purchase price of approximately $54.2 million, including customary closing adjustments. The Company funded these acquisitions with cash on hand and borrowings under the Operating Company’s revolving credit facility.

Divestiture

In the second quarter of 2024, the Company divested all of its non-Permian assets for a purchase price of approximately $87.2 million, including transaction costs and customary post-closing adjustments. The divested properties consisted of approximately 2,713 net royalty acres with current production of approximately 450 BO/d. The Company recorded the proceeds as a reduction of its full cost pool with no gain or loss recognized on the sale.

2023 Activity

Acquisitions

GRP Acquisition

On November 1, 2023, the Company acquired certain mineral and royalty interests from Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP, affiliates of Warwick Capital Partners and GRP Energy Capital (collectively, “GRP”) pursuant to a definitive purchase and sale agreement for approximately 9.02 million common units and $747.5 million in cash, including transaction costs and certain customary post-closing adjustments (the “GRP Acquisition”). The mineral and royalty interests acquired in the GRP Acquisition represent approximately 4,600 net royalty acres in the

Permian Basin, plus approximately 2,700 additional net royalty acres in other major basins. The cash consideration for the GRP Acquisition was funded through a combination of cash on hand and held in escrow, borrowings under the Operating Company's revolving credit facility, proceeds from the 2031 Notes (as defined in Note 6—Debt) and proceeds from the $200.0 million common unit issuance to Diamondback discussed further in Note 7—Stockholders' Equity.

2023 Drop Down

On March 8, 2023, the Company acquired certain mineral and royalty interests from subsidiaries of Diamondback for approximately $74.5 million in cash, including customary closing adjustments for net title benefits (the "2023 Drop Down"). The mineral and royalty interests acquired in the 2023 Drop Down represent approximately 660 net royalty acres in Ward County in the Southern Delaware Basin, 100% of which are operated by Diamondback, and have an average net royalty interest of approximately 7.2% and current production of approximately 300 BO/d. The Company funded the 2023 Drop Down through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. The 2023 Drop Down was accounted for as a transaction between entities under common control with the properties acquired recorded at Diamondback's historical carrying value in the Company's consolidated balance sheet. The historical carrying value of the properties approximated the 2023 Drop Down purchase price.

Other Acquisitions

Additionally during the year ended December 31, 2023 the Company acquired, in individually insignificant transactions from unrelated third-party sellers, mineral and royalty interests representing 286 net royalty acres in the Permian Basin for an aggregate purchase price of approximately $70.4 million, including customary closing adjustments. The Company funded these acquisitions with cash on hand and borrowings under the Operating Company's revolving credit facility.

2022 Acquisitions

Acquisitions

During the year ended December 31, 2022, in individually insignificant transactions, the Company acquired from unrelated third-party sellers mineral and royalty interests representing 375 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $65.8 million, including customary closing adjustments. The Company funded these acquisitions with cash on hand and borrowings under the Operating Company's revolving credit facility.

Divestitures

In the fourth quarter of 2022, the Company divested its entire position in the Eagle Ford Shale consisting of 681 net royalty acres of third-party operated acreage for an aggregate net sales price of $53.7 million, including customary closing adjustments.

In the third quarter of 2022, the Company divested 93 net royalty acres of third-party operated acreage located entirely in Loving county in the Delaware Basin for an aggregate net sales price of $29.9 million, including customary closing adjustments.

In the first quarter of 2022, the Company divested 325 net royalty acres of third-party operated acreage located entirely in Upton and Reagan counties in the Midland Basin for an aggregate net sales price of $29.3 million, including customary closing adjustments.

5. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following for the periods presented:

	December 31, 2024	December 31, 2023
	(In thousands)	
Oil and natural gas interests:		
Subject to depletion	$ 3,532,834	$ 2,859,642
Not subject to depletion	2,179,837	1,769,341
Gross oil and natural gas interests	5,712,671	4,628,983
Accumulated depletion and impairment	(1,080,764)	(866,352)
Oil and natural gas interests, net	4,631,907	3,762,631
Land	5,688	5,688
Property, net of accumulated depletion and impairment	$ 4,637,595	$ 3,768,319

Balance of costs not subject to depletion:	
Incurred in 2024	$ 798,705
Incurred in 2023	576,162
Incurred in 2022	33,053
Prior	771,917
Total not subject to depletion	$ 2,179,837

As of December 31, 2024 and 2023, the Company had mineral and royalty interests representing approximately 35,671 and 34,217 net royalty acres, respectively.

Costs associated with unevaluated properties are excluded from the full cost pool until a determination as to the existence of proved reserves can be made. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within eight to ten years.

Based on the results of the quarterly ceiling tests, the Company was not required to record an impairment on the Company's proved oil and natural gas interests for the years ended December 31, 2024, 2023 and 2022. In addition to commodity prices, the Company's production rates, levels of proved reserves, transfers of unevaluated properties and other factors will determine its actual ceiling test limitations and impairment analysis in future periods. If the trailing 12-month commodity prices were to fall as compared to the commodity prices used in prior quarters, the Company could have write-downs in subsequent quarters, which may be material.

6. DEBT

Long-term debt consisted of the following as of the dates indicated:

	December 31, 2024	December 31, 2023
	(In thousands)	
5.375% Senior Notes due 2027	$ 430,350	$ 430,350
7.375% Senior Notes due 2031	400,000	400,000
Revolving credit facility	261,000	263,000
Unamortized debt issuance costs	(5,836)	(6,903)
Unamortized discount	(2,535)	(3,365)
Total long-term debt	$ 1,082,979	$ 1,083,082

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

Issuance of 2031 Notes

On October 19, 2023, the Company completed an offering of $400.0 million in aggregate principal amount of its 7.375% Senior Notes maturing on November 1, 2031 (the “2031 Notes”). The Company received net proceeds of approximately $394.0 million, after deducting the initial purchasers’ discount and transaction costs from the 2031 Notes. The Company loaned the gross proceeds to the Operating Company, which used the proceeds to partially fund the cash portion of the GRP Acquisition.

The Notes

The Notes are senior unsecured obligations of the Company, initially guaranteed on a senior unsecured basis by the Operating Company, and will pay interest semi-annually. Diamondback will not guarantee the Notes. In the future, each of the Company’s restricted subsidiaries that either (i) guarantees any of its or a guarantor’s indebtedness, or (ii) is a domestic restricted subsidiary and is an obligor with respect to any indebtedness under any credit facility will be required to guarantee the Notes.

The Operating Company’s Revolving Credit Facility

On November 22, 2024, the Operating Company, as borrower, and the Company, as parent guarantor, entered into a thirteenth amendment to the existing credit facility, which among other things, (i) maintained the maximum credit amount of $2.0 billion, (ii) maintained the borrowing base of $1.3 billion, and (iii) increased the elected commitment amount from $850.0 million to $1.3 billion.

As of December 31, 2024, the Operating Company had $261.0 million of outstanding borrowings and $989.0 million available for future borrowings under the Operating Company’s revolving credit facility. For the years ended December 31, 2024, 2023 and 2022, the weighted average interest rate on borrowings under the Operating Company’s revolving credit facility was 7.34%, 7.41%, and 4.22%, respectively. The revolving credit facility will mature on September 22, 2028.

The outstanding borrowings under the credit facility bear interest at a rate elected by the Operating Company that is equal to (i) term SOFR plus 0.10% (“Adjusted Term SOFR”), or (ii) an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50%, and 1-month Adjusted Term SOFR plus 1.00%), in each case plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% per annum in the case of the alternative base rate and from 2.00% to 3.00% per annum in the case of Adjusted Term SOFR, in each case depending on the amount of the loans outstanding in relation to the commitment, which is calculated using the least of the maximum credit amount, the aggregate elected commitment amount and the borrowing base. The Operating Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment. The credit facility is secured by substantially all the assets of the Company and the Operating Company.

The credit facility contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, excess cash and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total net debt to EBITDAX, as defined in the credit facility	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit facility	Not less than 1.0 to 1.0
Ratio of secured debt to EBITDAX, as defined in the credit facility	Not greater than 2.5 to 1.0

As of December 31, 2024, the Operating Company was in compliance with all financial maintenance covenants under its credit facility.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2024, 2023 and 2022:

	Year Ended December 31,		
	2024	2023	2022
		(In thousands)	
Interest expense	$ 74,373	$ 48,222	$ 37,539
Other fees and expenses	1,529	836	2,883
Less: interest income	2,054	1,666	428
Interest expense, net	$ 73,848	$ 47,392	$ 39,994

7. STOCKHOLDERS' EQUITY

At December 31, 2024, the Company had a total of 102,977,142 shares of Class A Common Stock issued and outstanding and 85,431,453 shares of Class B Common Stock issued and outstanding. At December 31, 2024, all of the issued and outstanding shares of Class B Common Stock were beneficially owned by Diamondback, representing approximately 45% of the Company's total Common Stock outstanding. Diamondback also beneficially owned 85,431,453 OpCo Units, representing a 43% non-controlling ownership interest in the Operating Company, TWR IV beneficially owned 10,093,670 OpCo Units, representing a 5% non-controlling ownership interest in the Operating Company, and the Company owned the remaining 102,977,142 OpCo Units. The OpCo Units and the Company's Class B Common Stock beneficially owned by Diamondback are exchangeable from time to time for the Company's Class A Common Stock (that is, one OpCo Unit and one share of the Company's Class B Common Stock, together, are exchangeable for one share of the Company's Class A Common Stock).

In addition to the outstanding shares of the Company's Class B Common Stock, TWR IV was granted the TWR Class B Option to acquire 10.09 million shares of Class B Common Stock. The OpCo Units and, subject to the exercise of the TWR Class B Option, any shares of Class B Common Stock beneficially owned by TWR IV are under lockup until April 1, 2025, at which time each OpCo Unit and, subject to TWR IV's exercise of the TWR Class B Option, an equal number of shares of Class B Common Stock will become exchangeable by TWR IV for one share of the Company's Class A Common Stock. Any shares of Class A Common Stock issued to TWR IV in exchange for OpCo Units and an equal number of shares of Class B Common Stock will reduce the number of shares of Class B Common Stock available to TWR IV under the TWR Class B Option.

2024 Equity Offering

On September 13, 2024, the Company completed an underwritten public offering of approximately 11.50 million shares of its Class A Common Stock, which included 1.50 million shares issued pursuant to an option to purchase additional shares of Class A Common Stock granted to the underwriters, at a price to the public of $42.50 per share for total net proceeds of approximately $475.9 million, after the underwriters' discount and transaction costs (the "2024 Equity Offering"). The net proceeds were used to fund a portion of the cash consideration for the TWR Acquisition.

2023 Viper Issuance of Common Units to Diamondback

In October 2023, the Company issued approximately 7.22 million of its common units to Diamondback at a price of $27.72 per unit for total net proceeds of approximately $200.0 million (the "2023 Viper Issuance"). The net proceeds were used to fund a portion of the cash consideration for the GRP Acquisition. During 2024, Diamondback sold all of its shares of the Company's Class A Common Stock in the Diamondback Offering discussed in Note 1—Organization and Basis of Presentation.

Common Stock Repurchase Program

The Company's board of directors has authorized a $750.0 million common stock repurchase program, with respect to the repurchase of the Company's Class A Common Stock, excluding excise tax, over an indefinite period of time. The Company has and intends to continue to purchase shares of Class A Common Stock under the repurchase program opportunistically with funds from cash on hand, free cash flow from operations and potential liquidity events such as the sale of assets. This repurchase program may be suspended from time to time, modified, extended or discontinued by the Company's board of directors at any time.

During the year ended December 31, 2024, there were no repurchases under the repurchase program. Repurchases of $95.2 million for the year ended December 31, 2023 include approximately $28.7 million for the repurchase of 1.0 million shares of Class A Common Stock from GRP in a privately negotiated transaction in the fourth quarter of 2023. Repurchases of $150.6 million for the year ended December 31, 2022 include approximately $37.3 million for the repurchase of 1.5 million shares of Class A Common Stock from a significant stockholder in a privately negotiated transaction. As of December 31, 2024, $434.2 million remains available under the repurchase program, excluding excise tax.

Changes in Ownership of Consolidated Subsidiaries

Non-controlling interest in the accompanying consolidated financial statements represents Diamondback's and TWR IV's ownership in the net assets of the Operating Company. The non-controlling interests' relative ownership in the Operating Company can change due to the purchase or sale of the Company's Common Stock, the Company's public offerings of shares of Class A Common Stock for which proceeds are contributed to the Operating Company in exchange for OpCo Units, issuance of shares of Class A Common Stock or issuance of shares of Class B Common Stock and OpCo Units for acquisitions, share-based compensation, repurchases of shares of Class A Common Stock and distribution equivalent rights paid on the Company's Class A Common Stock. These changes in ownership percentage result in adjustments to non-controlling interest and stockholders' equity, tax effected, but do not impact earnings.

The following table summarizes the changes in stockholders' equity due to changes in ownership interest during the period:

	Year Ended December 31,		
	2024	2023	2022
	(In thousands)		
Net income (loss) attributable to the Company	$ 359,245	$ 200,088	$ 151,673
Change in ownership of consolidated subsidiaries	58,713	(101,632)	58,253
Change from net income (loss) attributable to the Company's stockholders and transfers with non-controlling interest	$ 417,958	$ 98,456	$ 209,926

Cash Dividends

The board of directors of the Company has established a dividend policy, consistent with the pre-Conversion distribution policy, whereby the Operating Company distributes all or a portion of its available cash on a quarterly basis to its unitholders (including Diamondback, the Company and, following the TWR Acquisition completed on October 1, 2024, TWR IV). The Company in turn distributes all or a portion of the available cash it receives from the Operating Company to holders of its Class A Common Stock through base and variable dividends. The Company currently intends to pay quarterly variable dividends of at least 75% of its available cash less the base dividend declared and the amount paid in stock repurchases as part of the Company's buyback program for the applicable quarter. Additionally, the Company's board of directors may approve certain one-time discretionary adjustments to the calculation of cash available for distribution.

The Company's available cash and the available cash of the Operating Company for each quarter, a non-GAAP measure, is determined by the Company's board of directors following the end of such quarter. The Company expects that its available cash will generally equal the Adjusted EBITDA attributable to the Company for the applicable quarter, less cash needed for income taxes payable, debt service, contractual obligations, fixed charges and reserves for future operating or capital needs that the Company's board of directors deems necessary or appropriate, lease bonus income (net of applicable taxes), distribution equivalent rights payments, preferred distributions, and an adjustment for changes in ownership interests that occurred subsequent to the quarter, if any.

The percentage of cash available for distribution by the Operating Company pursuant to the distribution policy may change quarterly to enable the Operating Company to retain cash flow to help strengthen the Company's balance sheet while also expanding the return of capital program through the Company's stock repurchase program. The Company is not required to pay dividends to the holders of its Class A Common Stock on a quarterly or other basis.

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

The Company is also required to pay a quarterly preferred dividend in respect of its Class B Common Stock in the aggregate amount of $20,000 per quarter, which is consistent with the Partnership's pre-Conversion preferred distribution requirement. Other than the preferred dividend requirement, the Company is not required to pay dividends to the holders of its Common Stock on a quarterly or other basis, and declaration of any other dividends in the future will be solely in the discretion of the Company's board of directors.

The following table presents information regarding cash distributions and dividends paid during the years ended December 31, 2024, 2023 and 2022 (in thousands, except for per unit amounts):

	Distributions (In thousands, except share amounts)						
Period	Amount per Operating Company Unit	Operating Company Distributions to Diamondback	Amount per Common Share	Common Unitholders(1)(2)	Declaration Date	Stockholder Record Date	Payment Date
2024							
Q4 2023	$ 0.69	$ 62,590	$ 0.56	$ 48,337	February 15, 2024	March 5, 2024	March 12, 2024
Q1 2024	$ 0.70	$ 59,803	$ 0.59	$ 54,077	April 25, 2024	May 15, 2024	May 22, 2024
Q2 2024	$ 0.76	$ 64,927	$ 0.64	$ 58,669	August 1, 2024	August 15, 2024	August 22, 2024
Q3 2024	$ 0.73	$ 62,366	$ 0.61	$ 62,932	October 31, 2024	November 14, 2024	November 21, 2024
2023							
Q4 2022	$ 0.54	$ 48,983	$ 0.49	$ 35,683	February 15, 2023	March 3, 2023	March 10, 2023
Q1 2023	$ 0.42	$ 38,097	$ 0.33	$ 23,797	April 26, 2023	May 11, 2023	May 18, 2023
Q2 2023	$ 0.44	$ 39,912	$ 0.36	$ 25,563	July 25, 2023	August 10, 2023	August 17, 2023
Q3 2023	$ 0.70	$ 63,497	$ 0.57	$ 49,126	November 2, 2023	November 16, 2023	November 24, 2023
2022							
Q4 2021	$ 0.47	$ 42,634	$ 0.47	$ 36,238	February 16, 2022	March 4, 2022	March 11, 2022
Q1 2022	$ 0.70	$ 63,497	$ 0.67	$ 51,680	April 27, 2022	May 12, 2022	May 19, 2022
Q2 2022	$ 0.87	$ 78,918	$ 0.81	$ 60,626	July 26, 2022	August 16, 2022	August 23, 2022
Q3 2022	$ 0.52	$ 47,170	$ 0.49	$ 36,076	November 3, 2022	November 17, 2022	November 25, 2022

(1) Dividends paid in the first quarter of 2024 include amounts paid to Diamondback for the 7,946,507 shares of Class A Common Stock then beneficially owned by Diamondback and distributions equivalent rights payments. As of March 31, 2024, Diamondback did not beneficially own any shares of Class A Common Stock.
(2) For distributions paid in 2023, includes amounts paid to Diamondback for the 731,500 common units then beneficially owned by Diamondback.

Cash dividends will be made to the common stockholders of record on the applicable record date, generally within 60 days after the end of each quarter.

Allocation of Net Income

The Partnership, as the previous managing member of the Operating Company, had an agreement, as amended on December 28, 2021, whereby special allocations of the Operating Company's income and gains over losses and deductions (but before depletion) were made to Diamondback through December 31, 2022. These special income allocations reduced the taxable income allocated to the Partnership's common unitholders during 2022.

8. EARNINGS PER COMMON SHARE

The net income (loss) per common share on the consolidated statements of operations is based on the net income (loss) attributable to the Company's Class A Common Stock for the years ended December 31, 2024 and 2023 and common units for the year ended December 31, 2022. For the year ended December 31, 2022, the Partnership's net income (loss) was allocated wholly to the common unitholders, as the General Partner did not have an economic interest. Payments made to the Company's stockholders are determined in relation to the cash dividend policy described in Note 7—Stockholders' Equity.

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

Basic and diluted earnings per common share are calculated using the two-class method. The two-class method is an earnings allocation proportional to the respective ownership among holders of Class A Common Stock and participating securities. Basic net income (loss) per common share is calculated by dividing net income (loss) by the weighted-average shares of Class A Common Stock outstanding during the period. Diluted net income (loss) per common share gives effect, when applicable, to unvested restricted stock units and performance restricted stock units granted under the LTIP.

A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Year Ended December 31,		
	2024	2023	2022
	(In thousands, except per share amounts)		
Net income (loss) attributable to the period	$ 359,245	$ 200,088	$ 151,673
Less: net income (loss) allocated to participating securities[(1)]	583	299	365
Net income (loss) attributable to common stockholders	$ 358,662	$ 199,789	$ 151,308
Weighted average common shares outstanding:			
Basic weighted average common shares outstanding	93,932	74,176	75,612
Effect of dilutive securities:			
Potential common shares issuable[(2)]	—	—	67
Diluted weighted average common shares outstanding	93,932	74,176	75,679
Net income (loss) per common share, basic	$ 3.82	$ 2.69	$ 2.00
Net income (loss) per common share, diluted	$ 3.82	$ 2.69	$ 2.00

(1) Unvested restricted stock units and performance restricted stock units that contain non-forfeitable distribution equivalent rights are considered participating securities and are therefore included in the earnings per share calculation pursuant to the two-class method.
(2) For the years ended December 31, 2024, 2023 and 2022 no significant potential common shares were excluded from the computation of diluted earnings per common share.

9. INCOME TAXES

The Company’s total income tax benefit for the year ended December 31, 2024, differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to the release of the remaining valuation allowance during the fourth quarter and net income attributable to non-controlling interests. For the years ended December 31, 2023 and 2022, respectively, total income tax expense differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to net income attributable to the non-controlling interest and the impact of reductions to the valuation allowance.

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

The components of the provision for income taxes and effective tax rates for the years ended December 31, 2024, 2023 and 2022 are as follows:

	Year Ended December 31,		
	2024	2023	2022
	(In thousands)		
Current income tax provision (benefit):			
Federal	$ 47,264	$ 50,414	$ 15,929
State	2,110	2,538	1,074
Total current income tax provision (benefit)	49,374	52,952	17,003
Deferred income tax provision (benefit):			
Federal	(148,439)	(6,532)	(49,656)
State	(646)	(468)	—
Total deferred income tax provision (benefit)	(149,085)	(7,000)	(49,656)
Total provision (benefit) from income taxes	$ (99,711)	$ 45,952	$ (32,653)
Effective tax rates	(19.8)%	8.4 %	(5.2)%

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

	Year Ended December 31,		
	2024	2023	2022
	(In thousands)		
Income tax expense (benefit) at the federal statutory rate (21%)	$ 105,826	$ 114,931	$ 130,694
Impact of nontaxable noncontrolling interest	(51,324)	(63,263)	(105,699)
State income tax expense (benefit), net of federal tax effect	2,028	1,657	846
Change in valuation allowance	(155,908)	(7,281)	(58,443)
Other, net	(333)	(92)	(51)
Provision for (benefit from) income taxes	$ (99,711)	$ 45,952	$ (32,653)

The components of the Company's deferred tax assets and liabilities as of December 31, 2024 and 2023 are as follows:

	Year Ended December 31,	
	2024	2023
	(In thousands)	
Deferred tax assets:		
Net operating loss and capital loss carryforwards	$ 13	$ 15
Investment in the Operating Company	185,228	170,164
Total deferred tax assets	185,241	170,179
Valuation allowance	(6)	(113,523)
Net deferred tax assets	185,235	56,656
Deferred tax liabilities:		
Other	386	—
Total deferred tax liabilities	386	—
Net deferred tax assets (liabilities)	$ 184,849	$ 56,656

At December 31, 2024, the Company has net deferred tax assets of approximately $184.8 million, including immaterial federal capital loss carryforwards expiring in 2026 and immaterial state operating loss carryforwards. Deferred taxes are provided on the difference between the Company's basis for financial accounting purposes and basis for federal income tax purposes in its investment in the Operating Company.

During the fourth quarter of 2024, the Company released its remaining valuation allowance of $155.9 million as a result of management's assessment of the realizability of future taxable income, which primarily contributed to the discrete income tax benefit of $149.1 million for the year ended December 31, 2024. During the years ended December 31, 2023 and 2022, the Company recognized discrete income tax benefits of $7.0 million and $49.7 million, respectively, related to a partial release of its beginning-of-the-year valuation allowance, based on a change in judgment about the realizability of its deferred tax assets in future years.

In March 2024, as part of the Diamondback Offering, Diamondback converted approximately 5.28 million shares of the Company's Class B Common Stock along with 5.28 million OpCo Units into an equivalent number of shares of Class A Common Stock. In connection with this transaction, the Company recognized a $28.2 million increase in its deferred tax asset and a $10.8 million increase in its valuation allowance through additional paid-in capital.

The Company principally operates in the state of Texas. For the years ended December 31, 2024 and 2023, the Company recognized $2.1 million and $2.5 million, respectively, in state income tax expense primarily for its share of Texas margin tax attributable to the Company's results which are included in a combined tax return filed by Diamondback. At December 31, 2024, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The Company's 2021 through 2024 tax years remain open to examination by tax authorities.

10. DERIVATIVES

During 2024, the Company used fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of its royalty income. At December 31, 2024, the Company has puts, costless collars and fixed price basis swap contracts outstanding.

The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with put contracts for oil based on WTI Cushing and fixed price basis swaps for oil based on the spread between the WTI Cushing crude oil price and the Argus WTI Midland crude oil price. The Company's fixed price basis swaps for natural gas are for the spread between the Waha Hub natural gas price and the Henry Hub natural gas price. The weighted average differential represents the amount of reduction to the WTI Cushing oil price and the Waha Hub natural gas price for the notional volumes covered by the basis swap contracts. Under the Company's costless collar contracts, each collar has an established floor price and ceiling price. When the settlement price is below the floor price, the counterparty is required to make a payment to the Company, and when the settlement price is above the ceiling price, the Company is required to make a payment to the counterparty. When the settlement price is between the floor and the ceiling, there is no payment required.

By using derivative instruments to economically hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are all participants in the amended and restated credit facility, which is secured by substantially all of the assets of the Operating Company; therefore, the Company is not required to post any collateral. The Company's counterparties have been determined to have an acceptable credit risk; therefore, the Company does not require collateral from its counterparties. Market risks involved in our use of derivative instruments relate to our potential inability to realize the benefits of any increases in commodity prices above the prices established by our derivative contracts.

As of December 31, 2024, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

					Swaps	Collars		Puts	
Settlement Month	Settlement Year	Type of Contract	Bbls/ MMBtu Per Day	Index	Weighted Average Differential	Weighted Average Floor Price	Weighted Average Ceiling Price	Strike Price	Deferred Premium
OIL									
Jan. - Mar.	2025	Puts	20,000	WTI Cushing	$—	$—	$—	$55.00	$(1.62)
Apr. - Jun.	2025	Puts	20,000	WTI Cushing	$—	$—	$—	$55.00	$(1.61)
NATURAL GAS									
Jan. - Dec.	2025	Basis Swaps	60,000	Waha Hub	$(0.80)	$—	$—	$—	$—
Jan. - Dec.	2025	Costless Collar	60,000	Henry Hub	$—	$2.50	$4.93	$—	$—

Balance Sheet Offsetting of Derivative Assets and Liabilities

The fair value of derivative instruments is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement. See Note 11—Fair Value Measurements for further details.

Gains and Losses on Derivative Instruments

The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations and the net cash receipts (payments) on derivatives for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
		(In thousands)	
Gain (loss) on derivative instruments(1)	$ 11,386	$ (25,793)	$ (18,138)
Net cash receipts (payments) on derivatives(2)	$ (2,978)	$ (13,319)	$ (31,319)

(1) The year ended December 31, 2024 includes an unrealized loss of $3.6 million for the change in fair value of the 2026 WTI Contingent Liability.

(2) The year ended December 31, 2022 includes cash paid on commodity contracts terminated prior to their contractual maturity of $6.6 million.

11. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is 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. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis on the Company's consolidated balance sheets, including the Company's commodity derivative instruments and the 2026 WTI Contingent Liability. The 2026 WTI Contingent Liability is recorded in "Other long-term liabilities" on the Company's consolidated balance sheet at December 31, 2024, with the change in fair value being recognized in "Gain (loss) on derivative instruments, net" on the Company's consolidated statements of operations for the year ended December 31, 2024.

The fair values of the Company's derivative contracts are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third-party, the contracted notional volumes, and time to maturity. The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The fair value of the 2026 WTI Contingent Liability is estimated using observable market data and a Monte Carlo pricing model, which are considered Level 2 inputs in the fair value hierarchy.

The following table provides (i) fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis, (ii) the gross amounts of recognized derivative assets and liabilities, (iii) the amounts offset under master netting arrangements with counterparties, and (iv) the resulting net amounts presented in the Company's consolidated balance sheets as of December 31, 2024 and December 31, 2023:

	As of December 31, 2024					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(In thousands)					
Assets:						
Current:						
Derivative instruments	$ —	$ 23,816	$ —	$ 23,816	$ (6,178)	$ 17,638
Liabilities:						
Current:						
Derivative instruments	$ —	$ 8,501	$ —	$ 8,501	$ (6,178)	$ 2,323
Non-current:						
2026 WTI Contingent Liability	$ —	$ 29,762	$ —	$ 29,762	$ —	$ 29,762

	As of December 31, 2023					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(In thousands)					
Assets:						
Current:						
Derivative instruments	$ —	$ 7,040	$ —	$ 7,040	$ (6,682)	$ 358
Non-current:						
Derivative instruments	$ —	$ 1,269	$ —	$ 1,269	$ (1,177)	$ 92
Liabilities:						
Current:						
Derivative instruments	$ —	$ 9,643	$ —	$ 9,643	$ (6,682)	$ 2,961
Non-current:						
Derivative instruments	$ —	$ 1,378	$ —	$ 1,378	$ (1,177)	$ 201

Assets and Liabilities Not Recorded at Fair Value

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated balance sheets:

	December 31, 2024		December 31, 2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Debt:				
Revolving credit facility	$ 261,000	$ 261,000	$ 263,000	$ 263,000
5.375% senior notes due 2027(1)	$ 427,049	$ 424,110	$ 425,949	$ 422,122
7.375% senior notes due 2031(1)	$ 394,930	$ 420,108	$ 394,133	$ 418,408

(1) The carrying value includes associated deferred loan costs and any discount.

The fair value of the Operating Company's revolving credit facility approximates the carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Notes was determined using the quoted market price at each period end, a Level 1 classification in the fair value hierarchy.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in certain circumstances. These assets and liabilities can include mineral and royalty interests acquired in asset acquisitions and subsequent write-downs of the Company's proved oil and natural gas interests to fair value when they are impaired or held for sale.

See Note 2—Summary of Significant Accounting Policies and Note 5—Oil and Natural Gas Interests for further discussion of non-recurring fair value adjustments.

Fair Value of Financial Assets

The Company has other financial instruments consisting of cash and cash equivalents, royalty income receivable, income tax receivable, prepaid expenses and other current assets, accounts payable, accrued liabilities and income taxes payable. The carrying value of these instruments approximate their fair value because of the short-term nature of the instruments.

12. COMMITMENTS AND CONTINGENCIES

The Company is a party to various routine legal proceedings, disputes and claims from time to time arising in the ordinary course of its business. While the ultimate outcome of any pending proceedings, disputes or claims, and any resulting impact on the Company, cannot be predicted with certainty, the Company's management believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Company's financial condition, results of operations or cash flows. The Company's assessment is based on information known about the pending matters and its experience in contesting, litigating and settling similar matters. Actual outcomes could differ materially from the Company's assessment. The Company records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

13. SUBSEQUENT EVENTS

Morita Ranches Acquisition

On February 14, 2025, the Company completed an acquisition of certain mineral and royalty interests located in Howard County, Texas from Morita Ranches Minerals, LLC ("Morita Ranches") (the "Morita Ranches Acquisition") pursuant to a definitive purchase and sale agreement for consideration consisting of approximately (i) $211.0 million in cash and (ii) 2.40 million OpCo Units together with an equal number of shares of the Company's Class B Common Stock issued to certain affiliate designees of Morita Ranches (the "Morita Ranches Equity Recipients"), subject to certain transaction costs and post-closing adjustments. At the closing of the Morita Ranches Acquisition, the Morita Ranches Equity Recipients (i) became parties to the Third Amended and Restated Limited Liability Agreement of OpCo, dated as of October 1, 2024, as amended, and (ii) entered into an Exchange Agreement with the Company and the Operating Company to provide for the right to exchange the OpCo Units and shares of our Class B Common Stock, acquired by the Morita Ranches Equity Recipients at the closing of the Morita Ranches Acquisition for an equal number of shares of the Company's Class A Common Stock. In addition, at the closing of the Morita Ranches Acquisition, the Company entered into a registration rights agreement with the Morita Ranches Equity Recipients, pursuant to which the Morita Ranches Equity Recipients received certain demand and piggyback registration rights with respect to the shares of the Company's Class A Common Stock that may be acquired by them in exchange for OpCo Units and shares of the Company's Class B Common Stock.

The mineral and royalty interests included in the Morita Ranches Acquisition represent approximately 1,691 net royalty acres in the Permian Basin, 75% of which are operated by Diamondback, and have an average net royalty interest of approximately 8.6% and current production of approximately 768 BO/d. The Company funded the cash consideration for the Morita Ranches Acquisition with cash on hand.

2025 Equity Offering

On February 3, 2025, the Company completed an underwritten public offering of approximately 28.34 million shares of Class A Common Stock, which included approximately 3.70 million shares issued pursuant to an option to purchase additional shares of Class A Common Stock granted to the underwriters, at a price to the public of $44.50 per share for total net proceeds of approximately $1.2 billion, after the underwriters' discount and transaction costs (the "2025 Equity Offering").

The Company intends to use the net proceeds from the 2025 Equity Offering to fund the cash consideration for Pending 2025 Drop Down (defined below), if it closes, and the remaining net proceeds will be used for general corporate purposes. If the Pending 2025 Drop Down does not close, the Company will use the net proceeds from the 2025 Equity Offering for general corporate purposes.

Pending 2025 Drop Down Transaction

On January 30, 2025, the Company and the Operating Company, as buyer parties, entered into a definitive equity purchase agreement with Endeavor Energy Resources, LP ("Endeavor") and 1979 Royalties, LP and 1979 Royalties GP, LLC (collectively, the "Endeavor Subsidiaries"), each of which is a subsidiary of Diamondback, to acquire the Endeavor Subsidiaries from Endeavor for consideration consisting of (i) $1.0 billion in cash and (ii) the issuance of 69.63 million OpCo Units and an equivalent number of shares of the Company's Class B Common Stock (collectively, the "Equity Issuance"), in each case subject to customary closing adjustments, including, among other things, for net title benefits (such transaction, the "Pending 2025 Drop Down"). The OpCo Units and the Class B Common Stock to be issued in the Pending 2025 Drop Down, as well as the OpCo Units and Class B Common Stock otherwise beneficially owned by Diamondback, are exchangeable from time to time for shares of our Class A Common Stock (that is, one OpCo Unit and one share of Class B Common Stock, together, are exchangeable for one share of Class A Common Stock). The shares of Class A Common Stock that may be issued to Diamondback and/or its subsidiaries upon exchange of their OpCo Units and shares of Class B Common Stock, including those OpCo Units and shares of Class B Common Stock to be issued at the closing of the Pending 2025 Drop Down, are subject to our existing registration rights agreement with Diamondback, dated as of November 13, 2023, previously filed by us with the SEC.

The mineral and royalty interests owned by the Endeavor Subsidiaries and to be acquired in the Pending 2025 Drop Down represent approximately 22,847 net royalty acres in the Permian Basin, 69% of which are operated by Diamondback, and have an average net royalty interest of approximately 2.8% and current oil production of approximately 17,097 BO/d (the "Endeavor Mineral and Royalty Interests"). The Endeavor Mineral and Royalty Interests include interests in horizontal wells comprised of 6,055 gross proved developed production wells (of which approximately 29% are operated by Diamondback), 116 gross completed wells and 394 gross drilled but uncompleted wells, all of which are principally concentrated in the Midland Basin, with the balance located primarily in the Delaware and Williston Basins.

The audit committee of the Company's board of directors, comprised of all independent directors and advised by its legal counsel and financial advisor, negotiated and approved the Pending 2025 Drop Down and the transactions contemplated thereby, and recommended that the board of directors approve the Pending 2025 Drop Down and the transactions contemplated thereby, in each case, subject to the Company's receipt of the requisite stockholder and regulatory approvals and the satisfaction or waiver of other closing conditions discussed below. Based on that recommendation, and subject to the same approvals and conditions, the board of directors also approved the Pending 2025 Drop Down on January 30, 2025.

The completion of the Pending 2025 Drop Down is subject to (i) the approval of the Pending 2025 Drop Down by (a) the holders of a majority of the voting power of the Company's Common Stock entitled to vote on such proposal, voting together as a single class, at the special meeting of our stockholders, excluding the shares beneficially owned by Diamondback and its subsidiaries, and (b) the holders of a majority of the Company's outstanding Common Stock, in each case, as required by Delaware law, (ii) regulatory clearance under the Hart-Scott-Rodino Antitrust Improvement Act and (iii) the satisfaction or waiver of other customary closing conditions. In addition, the Equity Issuance is subject to the approval by the Company's stockholders representing a majority of the total votes cast at the special meeting on such proposal, as required by the rules of Nasdaq Stock Market LLC. The Company expects to hold the special meeting of its stockholders and, subject to the satisfaction or waiver of the foregoing conditions, close the Pending 2025 Drop Down during the second quarter of 2025.

After giving effect to the 2025 Equity Offering and the Morita Ranches Acquisition, the Company currently estimates that following the closing of the Pending 2025 Drop Down, Diamondback will beneficially own approximately 52% of the Company's outstanding Common Stock, on a fully diluted basis.

The Company intends to fund the cash consideration for the Pending 2025 Drop Down with the proceeds from the 2025 Equity Offering. The Pending 2025 Drop Down will be accounted for as a transaction between entities under common control with the acquired properties recorded at Endeavor's historical carrying value in the Company's consolidated balance sheet.

Cash Dividend

On January 30, 2025, the board of directors of the Company approved a cash dividend for the fourth quarter of 2024 of $0.65 per share of Class A Common Stock and $0.69 per OpCo Unit, in each case, payable on March 13, 2025, to holders of record at the close of business on March 6, 2025. The dividend on Class A Common Stock consists of a base quarterly dividend of $0.30 per share and a variable quarterly dividend of $0.35 per share.

14. SEGMENT INFORMATION

As of December 31, 2024, the Company is managed on a consolidated basis as a single operating and reportable segment which is focused on owning and acquiring mineral and royalty interests primarily in the Permian Basin in West Texas. The Company's operating segment derives its revenue from customers through the receipt of royalty income on the sale of oil and natural gas products as well as other immaterial service contracts. See Note 3—Revenue from Contracts with Customers for further discussion of the Company's sources of revenue.

The Company's Chief Operating Decision Maker ("CODM") is a senior executive committee that is comprised of the Company's Chief Executive Officer and President. The CODM uses the Company's consolidated financial results to assess performance, allocate resources and make key operating decisions, obtaining the board's approval as required. The measures of segment profit or loss and total assets utilized by the CODM are net income and total assets, as reported on the consolidated statements of operations and the consolidated balance sheets, respectively. The significant expense categories, their amounts and other segment items that are regularly provided to the CODM are those that are reported in the Company's consolidated statements of operations as well as interest income and interest expense in Note 6—Debt.

The CODM uses consolidated net income as a measure of profitability to evaluate segment performance and to make capital allocation decisions such as reinvestment in the business or return of capital through the payment of base and variable dividends or repurchases under the share repurchase program.

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company’s oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion and amortization are as follows:

	December 31,	
	2024	2023
	(In thousands)	
Oil and natural gas interests:		
Proved	$ 3,532,834	$ 2,859,642
Unproved	2,179,837	1,769,341
Total oil and natural gas interests	5,712,671	4,628,983
Accumulated depletion and impairment	(1,080,764)	(866,352)
Net oil and natural gas interests capitalized	$ 4,631,907	$ 3,762,631

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition activities are as follows:

	Year Ended December 31,		
	2024	2023	2022
		(In thousands)	
Acquisition costs:			
Proved properties	$ 340,907	$ 402,659	$ 46,307
Unproved properties	830,450	758,342	16,624
Total	$ 1,171,357	$ 1,161,001	$ 62,931

Results of Operations from Oil and Natural Gas Producing Activities

Substantially all of the Company’s producing activities are from oil and natural gas activities and are included in the “—*Consolidated Statements of Operations”* above.

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates and their associated future net cash flows were prepared by our internal reservoir engineers and audited by Ryder Scott Company, L.P., independent petroleum engineers, as of December 31, 2024, 2023 and 2022. The reserve estimates represent the Company’s net revenue interest in the Company’s properties. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon SEC Prices for the periods ended December 31, 2024, 2023 and 2022, respectively. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. All of the Company’s proved reserves included in the reserve reports are located in the continental United States. Although the estimates are believed to be reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Viper Energy, Inc.

Notes to Consolidated Financial Statements - (Continued)

The following table presents changes in estimated proved reserves, which were prepared in accordance with the rules and regulations of the SEC:

	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBOE)[1]
Proved Developed and Undeveloped Reserves:				
As of December 31, 2021	69,240	183,690	28,033	127,888
Purchase of reserves in place	599	1,186	209	1,006
Extensions and discoveries	15,714	29,177	5,281	25,858
Revisions of previous estimates	1,453	15,248	4,483	8,477
Divestitures	(905)	(3,469)	(564)	(2,047)
Production	(7,097)	(15,868)	(2,540)	(12,282)
As of December 31, 2022	79,004	209,964	34,902	148,900
Purchase of reserves in place	10,469	27,011	4,006	18,977
Extensions and discoveries	13,636	34,632	6,150	25,558
Revisions of previous estimates	(5,178)	11,101	3,466	138
Production	(8,028)	(19,130)	(3,108)	(14,324)
As of December 31, 2023	89,903	263,578	45,416	179,249
Purchase of reserves in place	7,891	20,310	3,665	14,941
Extensions and discoveries	13,099	33,498	6,254	24,936
Revisions of previous estimates	(6,472)	4,449	2,837	(2,894)
Divestitures	(919)	(4,605)	(451)	(2,138)
Production	(9,939)	(24,606)	(4,181)	(18,221)
As of December 31, 2024	93,563	292,624	53,540	195,873
Proved Developed Reserves:				
December 31, 2022	54,817	161,119	25,621	107,291
December 31, 2023	69,043	221,462	37,417	143,371
December 31, 2024	76,020	253,271	45,633	163,865
Proved Undeveloped Reserves:				
December 31, 2022	24,187	48,845	9,281	41,609
December 31, 2023	20,860	42,116	7,999	35,878
December 31, 2024	17,543	39,353	7,907	32,009

(1) Includes total proved reserves of 84,226 MBOE, 91,417 MBOE, 81,895 MBOE and 69,060 MBOE as of December 31, 2024, 2023, 2022 and 2021, respectively, attributable to a non-controlling interest in the Company.

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2024, the Company’s total extensions and discoveries of 24,936 MBOE resulted primarily from the drilling of 1,170 new wells and from 447 new proved undeveloped locations added. The Company’s total downward revisions of previous estimated quantities of 2,894 MBOE were primarily attributable to negative revisions of (i) 6,539 MBOE associated with lower commodity prices, and (ii) 2,936 MBOE due primarily to PUD downgrades partially offset by positive revisions of 6,580 MBOE primarily attributable to performance revisions. Total purchases of reserves in place of 14,941 MBOE resulted primarily from the Tumbleweed Acquisitions and other acquisitions of certain mineral and royalty interests. Divestitures of 2,138 MBOE related primarily to non-core mineral and royalty interests.

During the year ended December 31, 2023, the Company’s total extensions and discoveries of 25,558 MBOE resulted primarily from the drilling of 904 new wells and from 179 new proved undeveloped locations added. The Company’s total positive revisions of previous estimated quantities of 138 MBOE consist of positive revisions of 5,688 MBOE primarily attributable to performance revisions which were largely offset by PUD downgrades of 5,548 MBOE. Total purchases of reserves in place of 18,977 MBOE resulted primarily from the GRP Acquisition and other acquisitions of certain mineral and royalty interests.

During the year ended December 31, 2022, the Company's total extensions and discoveries of 25,858 MBOE resulted primarily from the drilling of 636 new wells and from 199 new proved undeveloped locations added. The Company's total positive revisions of previous estimated quantities of 8,477 MBOE were due to positive revisions of 15,484 MBOE attributable to price and performance revisions which were partially offset by PUD downgrades of 7,007 MBOE. Total purchases of reserves in place of 1,006 MBOE resulted from multiple acquisitions of certain mineral and royalty interests.

Proved Undeveloped Reserves

As of December 31, 2024, the Company's PUD reserves totaled 17,543 MBbls of oil, 39,353 MMcf of natural gas and 7,907 MBbls of natural gas liquids, for a total of 32,009 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. The Company's PUD reserves were from 837 horizontal wells, all of which Diamondback operates. Of the horizontal locations, 219 are Middle Spraberry/Jo Mill wells, 212 are Wolfcamp A wells, 195 are Lower Spraberry wells, 144 are Wolfcamp B wells, 44 are Bone Spring wells, 16 are Dean wells and seven are Wolfcamp D wells.

The following table includes the changes in PUD reserves for 2024:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2023	35,878
Undeveloped reserves transferred to developed	(16,696)
Revisions	(1,934)
Purchases	4,913
Extensions and discoveries	9,848
Ending proved undeveloped reserves at December 31, 2024	32,009

The decrease in PUD reserves was primarily attributable to the conversion of 16,696 MBOE of PUD reserves into proved developed reserves and downward revisions of 1,934 MBOE primarily attributable to PUD downgrades of 2,642 MBOE. These reductions in PUD reserves were partially offset by positive additions of 9,848 MBOE, primarily from 447 new horizontal well locations attributable to extensions resulting from strategic drilling of wells to delineate our acreage position and acquisitions of 4,913 MBOE.

All of the Company's PUD drilling locations are scheduled to be drilled within five years from the date they were initially recorded. As of December 31, 2024, none of the Company's total proved reserves were classified as proved developed non-producing.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on SEC Prices. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

Viper Energy, Inc.
Notes to Consolidated Financial Statements - (Continued)

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves as of December 31, 2024, 2023 and 2022:

	December 31,		
	2024	2023	2022
		(In thousands)	
Future cash inflows	$ 8,322,795	$ 8,493,617	$ 10,072,969
Future production taxes	(578,310)	(593,840)	(729,256)
Future income tax expense	(748,375)	(934,392)	(1,465,160)
Future net cash flows	6,996,110	6,965,385	7,878,553
10% discount to reflect timing of cash flows	(3,676,566)	(3,778,499)	(4,424,457)
Standardized measure of discounted future net cash flows(1)	$ 3,319,544	$ 3,186,886	$ 3,454,096

(1) Includes a 43%, 51% and 55% non-controlling interest in the Company at December 31, 2024, 2023 and 2022, respectively.

The following table presents the SEC Prices as adjusted for differentials and contractual arrangements utilized in the computation of future cash inflows:

	December 31,		
	2024	2023	2022
Oil (per Bbl)	$ 75.61	$ 77.93	$ 95.04
Natural gas (per Mcf)	$ 0.49	$ 1.54	$ 5.74
Natural gas liquids (per Bbl)	$ 20.62	$ 23.79	$ 38.95

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	Year Ended December 31,		
	2024	2023	2022
		(In thousands)	
Standardized measure of discounted future net cash flows at the beginning of the period	$ 3,186,886	$ 3,454,096	$ 2,093,117
Purchase of minerals in place	354,874	473,742	30,331
Divestiture of reserves	(51,119)	—	(30,076)
Sales of oil and natural gas, net of production costs	(792,694)	(666,709)	(781,604)
Extensions and discoveries	640,438	626,854	844,010
Net changes in prices and production costs	(438,456)	(1,405,205)	1,131,202
Revisions of previous quantity estimates	(84,949)	2,726	309,338
Net changes in income taxes	70,333	212,391	(393,652)
Accretion of discount	373,790	427,998	234,717
Net changes in timing of production and other	60,441	60,993	16,713
Standardized measure of discounted future net cash flows at the end of the period	$ 3,319,544	$ 3,186,886	$ 3,454,096

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2024, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2024, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of our Company is responsible for establishing and maintaining adequate internal control over financial reporting of the Company. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in the Company's internal control over financial reporting and determined that the Company maintained effective internal control over financial reporting as of December 31, 2024.

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

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2024. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2024, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Viper Energy, Inc.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Viper Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2024, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2024, and our report dated February 26, 2025 expressed an unqualified opinion on those financial statements.

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 26, 2025

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2024.

We have adopted a Code of Business Conduct and Ethics that applies to our Chief Executive Officer, Chief Financial Officer, principal accounting officer and controller and persons performing similar functions. Any amendments to or waivers from the code of business conduct and ethics will be disclosed on our website. The Company also has made the Code of Business Conduct and Ethics available on our website under the “Investors—Corporate Governance” section at https://www.viperenergy.com. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2024.

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

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2024.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2024.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2024.

ITEM 9B. OTHER INFORMATION

None of the Company’s directors or officers adopted or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement during our fiscal year ended December 31, 2024.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

3. Exhibits

Exhibit Number	Description
2.1#	Purchase and Sale Agreement, dated as of September 11, 2024, by and among Tumbleweed Royalty IV, LLC, TWR IV Sellco Parent LLC (collectively, as sellers), Viper Energy Partners LLC (as buyer) and Viper Energy, Inc. (as parent) (incorporated by reference to Exhibit 2.1 of the Company’s Current Report on Form 8-K (File 001-36505) filed on September 11, 2024).
2.2#	Equity Purchase Agreement, dated as of January 30, 2025, by and among Endeavor Energy Resources, LP, as seller, 1979 Royalties LP and 1979 Royalties GP, LLC, as companies, Viper Energy Partners LLC, as buyer, and Viper Energy, Inc., as parent (incorporated by reference to Exhibit 2.1 of the Company’s Current Report on Form 8-K (File 001-36505) filed on January 30, 2025).
3.1	Certificate of Conversion of Viper Energy Partners LP (incorporated by reference to Exhibit 99.2 to the Current Report on Form 8-K, filed by Viper Energy Partners LP with the SEC on November 2, 2023).
3.2	Certificate of Incorporation of Viper Energy, Inc. (incorporated by reference to Exhibit 99.3 to the Current Report on Form 8-K, filed by Viper Energy Partners LP with the SEC on November 2, 2023).
3.3	Amended and Restated Bylaws of Viper Energy Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (File 001-36505), filed on December 9, 2024).
3.4	Third Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, dated as of October 1, 2024 (incorporated by reference to Exhibit 3.7 of the Company’s Current Report on Form 10-Q (File 001-36505), filed on November 7, 2024).
4.1*	Description of Securities of the Company.
4.2	Second Amended and Restated Registration Rights Agreement, dated as of November 10, 2023, effective as of November 13, 2023, by and between Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.3 of the Company’s Current Report on form 8-K (File 001-36505) filed on November 13, 2023).
4.3	Registration Rights Agreement, dated as of October 1, 2024, by and between Viper Energy, Inc. and Tumbleweed Royalty IV, LLC (incorporated by reference to Exhibit 4.3 of the Company’s Current Report on Form 8-K (File 001-36505) filed on October 2, 2024).
4.4*	Registration Rights Agreement, dated as of February 14, 2025, by and among Viper Energy, Inc. and certain affiliates of Morita Ranches Minerals, LLC.
4.5*	Exchange Agreement, dated as of February 14, 2025, by and among the Company, Viper Energy Partners LLC and certain affiliates of Morita Ranches Minerals, LLC.
4.6	Class B Common Stock Option Agreement, dated as of October 1, 2024, by and between Viper Energy, Inc., Viper Energy Partners LLC and Tumbleweed Royalty IV, LLC (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File 001-36505) filed on October 2, 2024).
4.7	Second Amended and Restated Exchange Agreement, dated October 1, 2024, by and among Viper Energy, Inc., Viper Energy Partners LLC, Diamondback E&P LLC, Diamondback Energy, Inc. and Tumbleweed Royalty IV, LLC (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File 001-36505) filed on October 2, 2024).
4.8	First Supplemental Indenture, dated as of November 13, 2023, among Viper Energy, Inc., as successor issuer to Viper Energy Partners LP, and Computershare Trust Company, National Association, as trustee, relating to 5.375% Senior Notes due 2027 (incorporated by reference to Exhibit 10.2 of the Partnership’s Current Report on Form 8-K (File 001-36505) filed on November 17, 2023).
4.9	Indenture, dated as of October 16, 2019, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor and Computershare Trust Company National Association, as successor trustee to Wells Fargo Bank, National Association, (including the form of Viper Energy Partners LP’s 5.375% Senior Notes due 2027) (incorporated by reference to Exhibit 4.1 of the Partnership’s Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.10	Indenture, dated as of October 19, 2023, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor and Computershare Trust Company National Association, as trustee (including the form of Viper Energy Partners LP’s 7.375% Senior Notes due 2031) (incorporated by reference to Exhibit 4.1 of the Partnership’s Current Report on Form 8-K (File 001-36505) filed on October 25, 2023).

Exhibit Number	Description
4.11	First Supplemental Indenture, dated as of November 13, 2023, by and between Viper Energy, Inc., as the successor issuer to Viper Energy Partners LP, and Computershare Trust Company, National Association, as trustee, relating to 7.375% Senior Notes due 2031 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File 001-36505) filed on November 17, 2023).
4.12	Third Supplemental Indenture, dated as of October 16, 2024, among King Snake Royalty LLC, Sidewinder Snake Royalty LLC, as the guaranteeing subsidiaries, Viper Energy, Inc., Viper Energy Partners LLC, Queen Snake Royalty LLC, Mamba Royalty LP, Moccasin Royalty LLC and Computershare Trust Company, National Association (successor to Wells Fargo Bank, National Association), as trustee under the indenture, dated as of October 16, 2019, providing for the issuance of 5.375% Senior Notes due 2027 (incorporated by reference to Exhibit 4.5 to the Company's Current Report on form 10-Q (File 001-36505) filed on November 7, 2024).
4.13	Third Supplemental Indenture, dated as of October 16, 2024, among King Snake Royalty LLC, Sidewinder Snake Royalty LLC, as the guaranteeing subsidiaries, Viper Energy, Inc., Viper Energy Partners LLC, Queen Snake Royalty LLC, Mamba Royalty LP, Moccasin Royalty LLC and Computershare Trust Company, National Association (successor to Wells Fargo Bank, National Association), as trustee under the indenture, dated as of October 19, 2023, providing for the issuance of 7.375% Senior Notes due 2031 (incorporated by reference to Exhibit 4.6 to the Company's Current Report on form 10-Q (File 001-36505) filed on November 7, 2024).
10.1 +	Services and Secondment Agreement, dated as of November 2, 2023, by and among Diamondback E&P LLC, Viper Energy Partners LP, Viper Energy Partners GP LLC and Viper Energy Partners LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by Viper Energy Partners LP with the SEC on November 2, 2023).
10.2	Amended and Restated Credit Agreement, dated as of July 20, 2018, by and among, Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on July 26, 2018).
10.3 +	Viper Energy, Inc. Amended and Restated 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (File No. 001-36505) filed on November 13, 2023).
10.4 +	First Amendment to Amended and Restated 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Form 10-K (File 001-36505) filed on February 22, 2024).
10.5 +	Viper Energy, Inc. 2024 Amended and Restated Long Term Incentive Plan (incorporated by reference to Appendix A to Schedule DEF 14A filed by the Company with the SEC on April 25, 2024).
10.6 +	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.5 to the Form 10-K (File 001-36505) filed on February 22, 2024).
10.7	Amended and Restated Tax Sharing Agreement, dated as of November 10, 2023, effective as of November 13, 2023, by and between the Viper Energy Partners LLC and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36505) filed on November 13, 2023).
10.8 +	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.7 to the Form 10-K (File 001-36505) filed on February 22, 2024).
10.9 +	Form of Performance-based Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.8 to the Form 10-K (File 001-36505) filed on February 22, 2024).
10.10 +*	2025 Form of Time Vesting Restricted Stock Unit Award Agreement.
10.11+*	2025 Form of Performance-Vesting Restricted Stock Unit Agreement.
10.12 +	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Annual Report on Form 10-K (File No. 001-36505) filed on February 18, 2020).
10.13	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on September 30, 2019).
10.14	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 10, 2019).

Exhibit Number	Description
10.15	Fourth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 29, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on December 5, 2019).
10.16	Fifth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of May 11, 2020, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2020).
10.17	Sixth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 6, 2020, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on November 12, 2020).
10.18	Seventh Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of June 2, 2021, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on June 8, 2021).
10.19	Eighth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of November 15, 2021, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on November 18, 2021).
10.20	Ninth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of November 18, 2022, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.18 of the Partnership's Current Report on Form 10-K (File 001-36505) filed on February 23, 2023).
10.21	Tenth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of May 31, 2023, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 6, 2023).
10.22	Eleventh Amendment to Amended and Restated Senior Secured Revolving Credit Agreement dated as of September 22, 2023, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on September 28, 2023).
10.23	Twelfth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement dated as of September 22, 2023, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on September 28, 2023).
10.24 *	Thirteenth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Third Amendment to Guaranty and Collateral Agreement dated as of November 22, 2024, by and among Viper Energy Partners LLC, as borrow, Viper Energy, Inc., as parent guarantor, Wells Fargo Bank, National Association, as administrative agent.
10.25	Subordinated Promissory Note, dated as of October 16, 2019, by Viper Energy Partners LLC in favor of Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
10.26	Subordinated Promissory Note, dated as of October 19, 2023, made by Viper Energy Partners LLC payable to Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 25, 2023).
19.1 *	General Insider Trading Policy.
19.2 *	Sixth Amended and Restated Supplemental Policy Concerning Trading in Securities of the Company and its Subsidiaries by Certain Designated Persons.

Exhibit Number	Description
21.1 *	List of Significant Subsidiaries of Viper Energy Inc.
23.1 *	Consent of Grant Thornton LLP.
23.2 *	Consent of Ryder Scott Company, LP.
31.1 *	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2 *	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1 ++	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
97.1	Viper Energy, Inc. Clawback Policy (incorporated by reference to Exhibit 97.1 to the Form 10-K (File 001-36505) filed on February 22, 2024).
99.1 *	Audit Report of Ryder Scott Company, L.P. dated January 13, 2025, with respect to an audit of the proved reserves, future production and income attributable to certain royalty interests of Viper Energy, Inc. as of December 31, 2024.
101	The following financial information from the Registrant's Annual Report on Form 10-K for the year ended December 31, 2024, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statement of Changes in Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Filed herewith.

\+ Management contract, compensatory plan or arrangement.

++ The certifications attached as Exhibit 32.1 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed “filed” by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

\# Schedules (or similar attachments) have been omitted pursuant to Item 601(a)(5) of Regulation S-K and will be provided to the Securities and Exchange Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this Annual Report to be signed on its behalf by the undersigned thereunto duly authorized.

VIPER ENERGY, INC.

Date: February 26, 2025

By: VIPER ENERGY, INC.

By: /s/ Kaes Van't Hof
Name: Kaes Van't Hof
Title: Chief Executive Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Kaes Van't Hof Kaes Van't Hof	Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2025
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2025
/s/ Steven E. West Steven E. West	Chairman of the Board and Director	February 26, 2025
/s/ Travis D. Stice Travis D. Stice	Director	February 26, 2025
/s/ W. Wesley Perry W. Wesley Perry	Director	February 26, 2025
/s/ Spencer D. Armour Spencer D. Armour	Director	February 26, 2025
/s/ James L. Rubin James L. Rubin	Director	February 26, 2025
/s/ Frank C. Hu Frank C. Hu	Director	February 26, 2025
/s/ Laurie H. Argo Laurie H. Argo	Director	February 26, 2025