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, 2022

OR

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

Commission File Number 001-35700

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

DE	**45-4502447**
(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 Telephone Number, Including Area Code): (432) 221-7400

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	FANG	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, 2022 was approximately $21.2 billion.

As of February 17, 2023, 183,590,330 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2023 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

DIAMONDBACK ENERGY, INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2022

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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, which we refer to as this Annual Report or this report:

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Argus WTI Midland	Crude oil price index at the Permian Basin.
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 BO per day.
BOE	One barrel of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
Brent	Brent sweet light crude oil.
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.
Developed acreage	Acreage assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
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 or dry well	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.
Estimated Ultimate Recovery or EUR	Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
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 and development costs	Capital costs incurred in the acquisition, exploitation and exploration 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 working interest is owned.
Henry Hub	Louisiana natural gas pricing index.
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 with 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 or other liquid hydrocarbons.
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.
MMcf/d	Million cubic feet of natural gas per day.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.

Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
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	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 strata penetrated by a well so that the fluids from one stratum 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 commercial 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.
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.
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.
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	West Texas natural gas index.
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.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms that are used in this Annual Report:

ASU	Accounting Standards Update.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173).
EPA	U.S. Environmental Protection Agency.
Equity Plan	The Company's 2021 Amended and Restated Equity Incentive Plan.
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.
NYMEX	New York Mercantile Exchange.
Rattler	Rattler Midstream LP, a Delaware limited partnership.
Rattler's GP	Rattler Midstream GP LLC, a Delaware limited liability company; the general partner of Rattler Midstream LP and a wholly owned subsidiary of the Company.
Rattler LLC	Rattler Midstream Operating LLC, a Delaware limited liability company and a subsidiary of Rattler.
Ryder Scott	Ryder Scott Company, L.P.
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.
Guaranteed Senior Notes	The outstanding senior notes issued by Diamondback Energy, Inc. under indentures where Diamondback E&P is the sole guarantor, consisting of the 3.250% Senior Notes due 2026, 3.500% Senior Notes due 2029, 3.125% Senior Notes due 2031, 6.250% Senior Notes due 2033, 4.400% Senior Notes due 2051, 4.250% Senior Notes due 2052 and 6.250% Senior Notes due 2053.
SOFR	The secured overnight financing rate.
TSR	Total stockholder return of the Company's common stock.
Viper	Viper Energy Partners LP, a Delaware limited partnership.
Viper's General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Viper LLC	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of Viper.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report 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 (including drilling plans and capital plans); estimates and projections of revenues, losses, costs, expenses, returns, cash flow, and financial position; reserve estimates and our ability to replace or increase reserves; anticipated benefits of strategic transactions (including acquisitions and divestitures); and plans and objectives of management (including plans for future cash flow from operations and for executing environmental strategies) 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 the Company 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 future performance and our actual outcomes could differ materially from what we have expressed in our forward-looking statements.

Factors that could cause our 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 such as the COVID-19 pandemic, 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, and inflation rates and concerns over a potential economic downturn or recession;
- regional supply and demand factors, including delays, curtailment delays or interruptions of production, or governmental orders, rules or regulations that impose production limits;
- 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 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 (among other things) 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 operations and our environmental and social responsibility projects;
- challenges with employee retention and an increasingly competitive labor market due to a sustained labor shortage or increased turnover caused by the COVID-19 pandemic;
- changes in availability or cost of rigs, equipment, raw materials, supplies, oilfield services;
- changes in safety, health, environmental, tax, and other regulations or requirements (including those addressing air emissions, water management, or the impact of global climate change);
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or from breaches of information technology systems of third parties with whom we transact business;
- lack of, or disruption in, access to adequate and reliable transportation, processing, storage, and other facilities for our oil, natural gas, and natural gas liquids;
- failures or delays in achieving expected reserve or production levels from existing and future oil and natural gas developments, including due to operating hazards, drilling risks, or the inherent uncertainties in predicting reserve and reservoir performance;

- difficulty in obtaining necessary approvals and permits;
- severe weather conditions;
- acts of war or terrorist acts and the governmental or military response thereto;
- changes in the financial strength of counterparties to our credit agreement and hedging contracts;
- changes in our credit rating; and
- the other risk and factors discussed 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, we operate in a very competitive and rapidly changing environment and 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

Except as noted, in this Annual Report on Form 10-K, we refer to Diamondback, together with its consolidated subsidiaries, as "we," "us," "our," or "the Company". This Annual Report includes certain terms commonly used in the oil and natural gas industry, which are defined above in the "Glossary of Oil and Natural Gas Terms."

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. We report operations in one reportable segment, the upstream segment. Prior to the Rattler Merger (as defined below), both the upstream operations segment and the midstream operations segment were considered separate reportable segments. Following the Rattler Merger, the Company determined only the upstream operations segment met the quantitative requirements of a reportable segment.

Our activities are primarily focused on horizontal development of the Spraberry and Wolfcamp formations of the Midland Basin and the Wolfcamp and Bone Spring formations of the Delaware Basin, both of which are part of the larger Permian Basin in West Texas and New Mexico. These formations are characterized by a high concentration of oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates.

At December 31, 2022, our total acreage position in the Permian Basin was approximately 615,348 gross (508,767 net) acres, which consisted primarily of 371,915 gross (325,540 net) acres in the Midland Basin and 201,624 gross (150,719 net) acres in the Delaware Basin.

In addition, our publicly traded subsidiary Viper Energy Partners LP, which we refer to as Viper, owns mineral interests in the Permian Basin. We own Viper's General Partner, and we own approximately 56% of the limited partner interests in Viper.

As of December 31, 2022, our estimated proved oil and natural gas reserves were 2,032,971 MBOE (which includes estimated reserves of 148,900 MBOE attributable to the mineral interests owned by Viper). Of these reserves, approximately 69% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 703 gross (650 net) horizontal well locations in which we have a working interest, and 15 horizontal wells in which we own only a mineral interest through Viper. As of December 31, 2022, our estimated proved reserves were approximately 53% oil, 23% natural gas and 24% natural gas liquids.

Significant Recent Acquisitions and Divestitures

Pending Non-Core Asset Divestiture

In February 2023, we entered into definitive sales agreements with unrelated third-party buyers to divest non-core assets consisting of approximately 19,000 net acres in Glasscock County and approximately 4,900 net acres in Ward and Winkler counties for combined total consideration of $439 million, subject to certain closing adjustments. Both of these transactions are expected to close in the second quarter of 2023, subject to completion of diligence and satisfaction of other customary closing conditions

Lario Acquisition

On January 31, 2023, we closed on our acquisition of all leasehold interests and related assets of Lario Permian, LLC, a wholly owned subsidiary of Lario Oil and Gas Company, and certain associated sellers (collectively "Lario"). The acquisition included approximately 25,000 gross (15,000 net) acres in the Midland Basin and certain related oil and gas assets (the "Lario Acquisition"), in exchange for 4.33 million shares of our common stock and $814 million in cash, including certain customary closing adjustments. The Lario Acquisition will be accounted for as a business combination in the first quarter of 2023, with the fair value of consideration allocated to the acquisition date fair value of assets and liabilities acquired.

FireBird Acquisition

On November 30, 2022, we closed on our acquisition of all leasehold interests and related assets of FireBird Energy LLC (the “FireBird Acquisition”), which included approximately 75,000 gross (68,000 net) acres in the Midland Basin and certain related oil and gas assets, in exchange for 5.92 million shares of the Company’s common stock and $787 million of cash including customary closing adjustments.

Rattler Merger

On August 24, 2022 (the “Effective Date”), we completed the merger with Rattler pursuant to which we acquired all of the approximately 38.51 million publicly held outstanding common units of Rattler in exchange for approximately 4.35 million shares of our common stock (the “Rattler Merger”). Rattler continued as the surviving entity, and is now our wholly-owned subsidiary. Following the Rattler Merger, we owned all of Rattler’s outstanding common units and Class B units, and Rattler GP remained the general partner of Rattler. Following the closing of the Rattler Merger, Rattler’s common units were delisted from the NASDAQ Global Select Market and Rattler filed a certification on Form 15 with the SEC requesting the deregistration of its common units and suspension of Rattler’s reporting obligations under the Exchange Act.

See Note 4—Acquisitions and Divestitures and Note 16—Subsequent Events included in the notes to the consolidated financial statements included elsewhere in this Annual Report for additional discussion of our acquisitions and divestitures during 2022.

Commodity Prices

Prices for oil, natural gas and natural gas liquids are determined primarily by prevailing market conditions. Regional and worldwide economic activity, including any economic downturn or recession that has occurred or may occur in the future, 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. The war in Ukraine, the COVID-19 pandemic, rising interest rates, global supply chain disruptions, concerns about a potential economic downturn or recession and recent measures to combat persistent inflation have continued to contribute to economic and pricing volatility during 2022. Although the impact of inflation on our business has been insignificant in prior periods, inflation in the U.S. has been rising at its fastest rate in over 40 years, creating inflationary pressure on the cost of services, equipment and other goods in the energy industry and other sectors, which is contributing to labor and materials shortages across the supply-chain. Additionally, OPEC and its non-OPEC allies, known collectively as OPEC+, continues to meet regularly to evaluate the state of global oil supply, demand and inventory levels. As such, pricing may remain volatile during 2023.

Despite continuing favorable commodity prices and rising demand, we kept our production relatively flat during 2022, using excess cash flow for debt repayment and return to our stockholders rather than expanding our drilling program.

Our Business Strategy

Our business strategy includes the following:

- **Exercise Capital Discipline.** During 2022, we continued building on our execution track record, generating free cash flow while keeping capital costs under control. Our efficiency gains, particularly in the Midland Basin drilling and completion programs, enabled us to mitigate certain inflationary pressures on variable well costs, which led to a total capital expenditure amount of $1.9 billion, consistent with our guidance presented in November of 2022. We expect to continue to exercise capital discipline and plan to spend between $2.50 billion and $2.70 billion in 2023, with the goal of maintaining flat oil production throughout the year. This capital range accounts for the inflationary pressures we expect to see in 2023.

- **Focus on low cost development strategy and continuous improvement in operational, capital allocation and cost efficiencies.** Our acreage position is generally in contiguous blocks which allows us to develop this acreage efficiently with a “manufacturing” strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 98% of our acreage, which allows us to efficiently manage our operating costs, pace of development activities and the gathering and marketing of our production. Our average 83% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- **Continue to deliver on our enhanced capital return program.** We expect to be in a position to continue to deliver on our enhanced capital return program, through which we intend to distribute 75% of our quarterly free cash flow to our stockholders. Our capital return program is currently focused on our sustainable and growing base dividend and a combination of stock repurchases and variable dividends.

- **Leverage our experience operating in the Permian Basin.** Our executive team, which has significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by optimizing and enhancing our drilling and completion techniques. Our focus on efficient drilling and completion techniques is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. We believe that the experience of our executive team in deviated and horizontal drilling and completions has helped reduce the execution risk normally associated with these complex well paths. In addition, our completion techniques are continually evolving as we evaluate and implement hydraulic fracturing practices that have and are expected to continue to increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other top operators in the area in an effort to benchmark our performance and adopt best practices compared to our peers.

- **Pursue strategic acquisitions with substantial resource potential.** We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential. We believe our executive team, with its extensive experience in the Permian Basin, has a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets.

- **Maintain financial flexibility.** We seek to maintain a conservative financial position. As of December 31, 2022, Diamondback had $139 million of standalone cash and cash equivalents and our borrowing base was set at $1.6 billion which was fully available for future borrowings. As of December 31, 2022, Viper LLC had $18 million of cash and cash equivalents, $152 million in outstanding borrowings and $348 million available for future borrowings under its revolving credit facility.

- **Deliver on our commitment to environmental, social and governance (“ESG”) performance**. We are committed to the safe and responsible development of our resources in the Permian Basin. Our approach to ESG is evidenced through our commitment to people, safety, environmental responsibility, community and sound governance practices. In September 2022, we announced our medium-term goal to reduce Scope 1 and Scope 2 greenhouse gas (“GHG”) intensity by at least 50%, from 2020 levels by 2030 and a short-term goal to implement continuous emission monitoring systems on our facilities to cover at least 90% of operated oil production by the end of 2023.

Our Strengths

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

- **Oil rich resource base in one of North America’s leading resource plays.** Substantially all of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Permian Basin. Our production for the year ended December 31, 2022 was approximately 58% oil, 21% natural gas liquids and 21% natural gas. As of December 31, 2022, our estimated net proved reserves were comprised of approximately 53% oil, 23% natural gas and 24% natural gas liquids.

- **Multi-year drilling inventory in one of North America’s leading oil resource plays.** We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed economic price of approximately $50.00 per Bbl WTI, we currently have approximately 8,276 gross (6,055 net) identified potential horizontal drilling locations on our acreage, based on our evaluation of applicable geologic and engineering data. These gross identified economic potential horizontal locations have an average lateral length of approximately 9,234 feet, with the actual length depending on lease geometry and other considerations. These locations exist across most of our acreage blocks and in multiple horizons. The ultimate inter-well spacing at these locations may vary due to different factors, which would result in a higher or lower location count. In addition, we have approximately 5,383 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including additional horizontal drilling opportunities and strategic leasehold acquisitions.

- **Experienced, incentivized and proven management team.** Our executive team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. Our executive team has significant experience with both drilling and completing horizontal wells in addition to horizontal well reservoir and geologic expertise, which is of strategic importance as we expand our horizontal drilling activity.

- **Favorable operating environment.** We have focused our drilling and development operations in the Permian Basin, one of the longest operating 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 of the Permian Basin is more stable and predictable, and that we are faced with less operational risks in the Permian Basin, as compared to emerging hydrocarbon basins.

- **High degree of operational control.** We are the operator of approximately 98% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. We retain the ability to increase or decrease our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Our Properties

Location and Land

The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States. As of December 31, 2022, our total acreage position in the Permian Basin was approximately 615,348 gross (508,767 net) acres, which consisted primarily of 371,915 gross (325,540 net) acres in the Midland Basin and 201,624 gross (150,719 net) acres in the Delaware Basin. In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 775,180 gross acres (26,315 net) royalty acres in the Permian Basin. Approximately 57% of these net royalty acres are operated by us.

We have been developing multiple pay intervals in the Permian Basin through horizontal drilling and believe that there are opportunities to target additional intervals throughout the stratigraphic column. We believe our significant experience drilling, completing and operating horizontal wells will allow us to efficiently develop our remaining inventory and ultimately target other horizons that have limited development to date. The following table presents horizontal producing wells in which we have a working interest as of December 31, 2022:

Basin	Number of Horizontal Wells
Midland	2,310
Delaware	891
Other	53
Total(1)	3,254

(1) Of these 3,254 total horizontal producing wells, we are the operator of 2,771 wells and have a non-operated working interest in 483 additional wells.

The following table presents the average number of days in which we were able to drill our horizontal wells to total depth specified below during the year ended December 31, 2022:

	Average Days to Total Depth
Midland Basin	
7,500 foot lateral	7
10,000 foot lateral	12
13,000 foot lateral	15
15,000 foot lateral	16
Delaware Basin	
7,500 foot lateral	28
10,000 foot lateral	17
13,000 foot lateral	20
15,000 foot lateral	14

Further advances in drilling and completion technology may result in economic development of zones that are not currently viable.

Midstream Assets

As of December 31, 2022, we own and operate 770 miles of crude oil gathering pipelines and a fully integrated water system on acreage that overlays our nine core Midland and Delaware Basin development areas. Our crude oil infrastructure assets, which consist of gathering pipelines and metering facilities gather crude oil from horizontal and vertical wells in our ReWard, Spanish Trail, Pecos and Fivestones areas within the Permian Basin. Our water sourcing and distribution assets consist of water wells, frac pits, pipelines and water treatment and recycling facilities, which collectively gather and distribute water from Permian Basin aquifers to our drilling and completion sites through buried pipelines and temporary surface pipelines.

As of December 31, 2022, we also owned interests in the following midstream investments:

- a 10% equity interest in EPIC Crude Holdings LP, which owns and operates a long-haul crude oil pipeline from the Permian Basin and the Eagle Ford Shale to Corpus Christi, Texas that is capable of transporting approximately 600,000 Bbl/d.
- a 10% equity interest in Gray Oak Pipeline, LLC, which owns and operates a long-haul crude oil pipeline that is capable of transporting 900,000 Bbl/d from the Permian Basin and the Eagle Ford Shale to points along the Texas Gulf Coast, including a marine terminal connection in Corpus Christi, Texas. The Company subsequently divested its investment in Gray Oak Pipeline, LLC in January 2023.
- a 4% equity interest in Wink to Webster Pipeline LLC, which owns and operates a crude oil pipeline that is capable of transporting approximately 1,000,000 Bbl/d from origin points at Wink and Midland in the Permian Basin for delivery to multiple Houston area locations.
- a 43% equity interest in OMOG JV LLC, which operates approximately 400 miles of crude oil gathering and regional transportation pipelines and approximately 350,000 barrels of crude oil storage in Midland, Martin, Andrews and Ector Counties, Texas.
- a 25% equity interest in Remuda Midstream Holdings LLC, which we refer to as the WTG joint venture, which owns and operates an interconnected gas gathering system and seven major gas processing plants servicing the Midland Basin with 1,100 MMcf/d of total processing capacity with additional gas gathering and processing expansions planned.
- a 10% equity interest in BANGL LLC, which we refer to as the BANGL joint venture. The BANGL pipeline, which began full commercial service in the fourth quarter of 2021, provides NGL takeaway capacity from the MPLX and WTG gas processing plants in the Permian Basin to the NGL fractionation hub in Sweeny, Texas and has expansion capacity of up to 300,000 Bbl/d.

For additional information regarding our equity method investments as of December 31, 2022, see Note 7—Equity Method Investments and Note 16—Subsequent Events to our consolidated financial statements included elsewhere in this Annual Report.

Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Bone Spring, Wolfcamp, Strawn, Atoka and Barnett/Meramec formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties. Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Permian Spraberry, Dean and Wolfcamp formations, which we collectively refer to as the Wolfberry play. Since then, we and most other operators are almost exclusively drilling horizontal wells in the development of unconventional reservoirs in the Permian Basin. As of December 31, 2022, we held working interests in 6,489 gross (5,574 net) producing wells and only royalty interests in 5,455 additional wells.

Geology

The Greater Permian Basin formed as an area of rapid Pennsylvanian-Permian subsidence in response to dynamic structural influence of the Marathon Uplift and Ancestral Rockies. It is one of the most productive sedimentary basins in the U.S., with established oil and natural gas production from several stacked reservoirs of varying age ranges, most notably Permian aged sediments. In particular, the Permian aged Wolfcamp, Spraberry and Bone Spring Formations have been heavily targeted for several decades. First, through vertical commingling of these zones and, more recently, through horizontal exploitation of each individual horizon. Prior to deposition of the Wolfcamp, Spraberry and Bone Spring Formations, the area of the present-day Permian Basin was a continuous sedimentary feature called the Tabosa Basin. During this time, Ordovician, Silurian, Devonian and Mississippian sediments were laid down in a primarily open marine, shelf setting. However, some time frames saw more restrictive settings that lead to deposits of organically rich mudstone such as the Devonian Woodford and Mississippian Barnett/Meramec. These formations are important sources and, more recently, reservoirs within the present-day Greater Permian Basin.

The Spraberry and Bone Spring Formations were deposited as siliciclastic and carbonate turbidites and debris flows along with pelagic mudstones in a deep-water, basinal environment, while the Wolfcamp reservoirs consist of debris-flow, grain-flow and fine-grained pelagic sediments, which were also deposited in a basinal setting. The best carbonate reservoirs within the Wolfcamp, Spraberry and Bone Spring are generally found in close proximity to the Central Basin Platform, while mudstone reservoirs thicken basin-ward, away from the Central Basin Platform. The mudstone within these reservoirs is organically rich, which when buried to sufficient depth for thermal maturation, became the source of the hydrocarbons found both within the mudstones themselves and in the interbedded conventional clastic and carbonate reservoirs. Due to this complexity, the Wolfcamp, Spraberry and Bone Spring intervals are a hybrid reservoir system that contains characteristics of both unconventional and conventional reservoirs.

We have successfully developed several hybrid reservoir intervals within the Clearfork, Spraberry/Bone Spring, Wolfcamp and Barnett/Meramec formations since we began horizontal drilling in 2012. The mudstones and some clastics exhibit low permeabilities which necessitate the need for hydraulic fracture stimulation to unlock the vast storage of hydrocarbons in these targets.

We possess, or are in the process of acquiring, 3-D seismic data over substantially all of our major asset areas. Our extensive geophysical database currently includes approximately 5,383 square miles of 3-D data. This data will continue to be utilized in the development of our horizontal drilling program and identification of additional resources to be exploited.

Recent and Future Activity

During 2023, we expect to drill an estimated 325 to 345 gross (293 to 311 net) operated horizontal wells and complete an estimated 330 to 350 gross (297 to 315 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2023 will be between \$2.50 billion and \$2.70 billion, consisting of \$2.25 billion to \$2.41 billion for horizontal drilling and completions including non-operated activity and capital workovers, \$170 million to \$190 million for infrastructure and environmental and $80 million to $100 million for midstream investments, excluding joint venture investments and the cost of any leasehold and mineral interest acquisitions. During the year ended December 31, 2022, we drilled 240 gross (223 net) and completed 255 gross (236 net) operated horizontal wells. During the year ended December 31, 2022, our capital expenditures for drilling, completing and equipping wells and infrastructure additions to oil and natural gas properties were $1.9 billion. In addition, we spent $84 million for oil and natural gas midstream assets.

We were operating 19 drilling rigs and four completion crews at December 31, 2022 and currently intend to operate between 13 and 19 rigs and four and seven completion crews on average in 2023. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans in response to market conditions.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

The estimated reserves as of December 31, 2022 are based on reserve estimates prepared by our internal reservoir engineers and audited by Ryder Scott, an independent petroleum engineering firm. Our historical reserve estimates as of December 31, 2021 and 2020 were prepared by Ryder Scott. 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 audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates for 2022. The proved reserve audit performed by Ryder Scott for 2022 covered 100% of our total proved reserves.

Under SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations 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, 2022 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: (1) performance-based methods, (2) volumetric-based methods and (3) 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 include, but may not be 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 developed non-producing and 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 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" of this report. As a result, we maintain an internal staff of petroleum engineers and geoscience professionals that have an internal control process to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical staff met with our independent reserve auditor periodically during their audit of the period covered by the reserve reports 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 engineers for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

The Senior Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all our reserve estimates and overseeing communications with our independent reserve auditor. The Senior Vice President of Reservoir Engineering is a petroleum engineer with over 19 years of reservoir and operations experience and our geoscience staff has an average of approximately 14 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. Ryder Scott performed an independent analysis during its audit of our estimated reserves for 2022 and any differences were reviewed with our Senior Vice President of Reservoir Engineering. For 2022, our reserve auditor's estimates of our proved reserves did not materially differ 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 the following:

- review and verification of historical production data, which is based on actual production as reported by us;
- 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 our Senior Vice President of Reservoir Engineering to our Executive Vice President—Operations;
- prior to finalizing the reserve report, a review of our preliminary proved reserve estimates by our Chief Executive Officer, President and Chief Financial Officer, Executive Vice President and Chief Operating Officer, Senior Vice President of Reservoir Engineering 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.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2022, 2021 and 2020 (including those attributable to Viper), which were prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States. As of December 31, 2022, none of our total proved reserves were classified as proved developed non-producing.

	As of December 31,		
	2022	2021	2020
Estimated Proved Developed Reserves:			
Oil (MBbls)	699,513	620,474	443,464
Natural gas (MMcf)	2,122,782	1,770,688	1,085,035
Natural gas liquids (MBbls)	350,243	285,513	192,495
Total (MBOE)	1,403,553	1,201,102	816,798
Estimated Proved Undeveloped Reserves:			
Oil (MBbls)	369,995	307,815	315,937
Natural gas (MMcf)	746,079	815,119	522,029
Natural gas liquids (MBbls)	135,076	144,221	96,701
Total (MBOE)	629,418	587,889	499,643
Estimated Net Proved Reserves:			
Oil (MBbls)	1,069,508	928,289	759,401
Natural gas (MMcf)	2,868,861	2,585,807	1,607,064
Natural gas liquids (MBbls)	485,319	429,734	289,196
Total (MBOE)(1)	2,032,971	1,788,991	1,316,441
Percent proved developed	69%	67%	62%

(1) Estimates of reserves as of December 31, 2022, 2021 and 2020 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2022, 2021 and 2020, respectively, in accordance with SEC guidelines. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties, all of which are located within the continental United States. Although we believe these estimates are 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. See "Item 1A. Risk Factors" for a discussion of risks and uncertainties associated with our estimates of proved reserves and related factors, and see Note 18—Supplemental Information on Oil and Natural Gas Operations of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of our reserve estimates and pricing.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2022, our proved undeveloped reserves totaled 369,995 MBbls of oil, 746,079 MMcf of natural gas and 135,076 MBbls of natural gas liquids, for a total of 629,418 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table includes the changes in PUD reserves for 2022 (MBOE):

Beginning proved undeveloped reserves at December 31, 2021	587,889
Undeveloped reserves transferred to developed	(155,457)
Revisions	(82,619)
Purchases	8,734
Divestitures	(93)
Extensions and discoveries	270,964
Ending proved undeveloped reserves at December 31, 2022	629,418

The increase in proved undeveloped reserves was primarily attributable to extensions of 256,007 MBOE from 311 gross (287 net) wells in which we have a working interest and 14,957 MBOE from 199 gross wells in which Viper owns royalty interests. Of the 311 gross working interest wells, 261 were in the Midland Basin and 50 were in the Delaware Basin. Transfers of 155,457 MBOE from undeveloped to developed reserves were the result of drilling or participating in 168 gross (155 net) horizontal wells in which we have a working interest and 115 gross wells in which we also have a royalty interest or mineral interest through Viper. Downward revisions of 82,619 MBOE were primarily the result of negative revisions of 94,880 MBOE due to downgrades related to changes in the corporate development plan, and positive revisions of 12,261

MBOE attributable to higher commodity prices. Purchases of 8,734 MBOE consisted of 8,367 MBOE primarily from the FireBird Acquisition, and 367 MBOE of Viper's royalty interest purchases.

Costs incurred relating to the development of PUDs were approximately $566 million during 2022. Estimated future development costs relating to the development of PUDs are projected to be approximately $1.4 billion in 2023, $1.4 billion in 2024, $882 million in 2025 and $659 million in 2026. Since our formation in 2011, our average drilling costs and drilling times have been reduced, and we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed price of approximately $50.00 per Bbl WTI, we currently have approximately 8,276 gross (6,055 net) identified economic potential horizontal drilling locations on our acreage based on our evaluation of applicable geologic and engineering data. With our current development plan, we expect to continue our strong PUD conversion ratio in 2023 by converting an estimated 33% of our PUDs to a proved developed category and developing approximately 80% of the consolidated 2022 year-end PUD reserves by the end of 2025. As of December 31, 2022, all of our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

The following table presents the number of gross identified economic potential horizontal drilling locations by basin:

	Number of Identified Economic Potential Horizontal Drilling Locations
Midland Basin	
Lower Spraberry(1)	1,100
Middle Spraberry(1)	924
Wolfcamp A(2)	665
Wolfcamp B(2)	793
Other	1,772
Total Midland Basin	5,254
Delaware Basin	
2nd Bone Springs(3)	652
3rd Bone Springs(3)	963
Wolfcamp A(3)	359
Wolfcamp B(3)	585
Other	463
Total Delaware Basin	3,022
Total	8,276

(1) Our current location count is based on 660 foot to 880 foot spacing in Midland, Martin and northeast Andrews counties, depending on the prospect area and 880 foot spacing in all other counties.
(2) Our current location count is based on 660 foot to 880 foot spacing in Midland and Howard counties, depending on the prospect area and 880 foot spacing in all other counties.
(3) Our current location count is based on 880 foot to 1,320 foot spacing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following tables set forth information regarding our net production of oil, natural gas and natural gas liquids by basin for each of the periods indicated:

	Midland Basin	Delaware Basin	Other[1]	Total
Production Data:				
Year Ended December 31, 2022				
Oil (MBbls)	58,803	22,681	132	81,616
Natural gas (MMcf)	116,579	59,338	459	176,376
Natural gas liquids (MBbls)	20,800	9,016	64	29,880
Total (MBOE)	99,033	41,587	273	140,892
Year Ended December 31, 2021				
Oil (MBbls)	52,112	25,672	3,738	81,522
Natural gas (MMcf)	96,083	66,034	7,289	169,406
Natural gas liquids (MBbls)	17,010	8,749	1,487	27,246
Total (MBOE)	85,136	45,427	6,440	137,002
Year Ended December 31, 2020				
Oil (MBbls)	38,313	27,703	166	66,182
Natural gas (MMcf)	68,529	61,606	414	130,549
Natural gas liquids (MBbls)	12,597	9,295	89	21,981
Total (MBOE)	62,332	47,266	324	109,921

(1) Production data includes (i) Rockies, (ii) High Plains beginning January 1, 2021, (iii) Eagle Ford Shale through October 1, 2022, the effective date on which the properties were divested and (iv) Central Basin Platform through December 31, 2020.

The following table sets forth certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2022	2021	2020
Average Prices:			
Oil ($ per Bbl)	$ 93.85	$ 66.19	$ 36.41
Natural gas ($ per Mcf)	$ 4.86	$ 3.36	$ 0.82
Natural gas liquids ($ per Bbl)	$ 35.07	$ 28.70	$ 10.87
Combined ($ per BOE)	$ 67.90	$ 49.25	$ 25.07
Oil, hedged ($ per Bbl)(1)	$ 86.76	$ 52.56	$ 40.34
Natural gas, hedged ($ per Mcf)(1)	$ 4.12	$ 2.39	$ 0.67
Natural gas liquids, hedged ($ per Bbl)(1)	$ 35.07	$ 28.33	$ 10.83
Average price, hedged ($ per BOE)(1)	$ 62.85	$ 39.87	$ 27.26
Average Costs per BOE:			
Lease operating expenses	$ 4.63	$ 4.12	$ 3.87
Production and ad valorem taxes	4.34	3.10	1.77
Gathering and transportation expense	1.83	1.55	1.27
General and administrative - cash component	0.63	0.69	0.46
Total operating expense - cash	$ 11.43	$ 9.46	$ 7.37
General and administrative - non-cash component	$ 0.39	$ 0.37	$ 0.34
Depletion	8.87	8.77	11.30
Interest expense, net	1.13	1.45	1.79
Merger and integration expense	0.10	0.57	—
Total expenses	$ 10.49	$ 11.16	$ 13.43

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices and include gains and losses on cash settlements for matured commodity derivatives, which we do not designate for hedge accounting. Hedged prices exclude gains or losses resulting from the early settlement of commodity derivative contracts.

Wells Drilled and Completed in 2022

The following table sets forth the total number of operated horizontal wells drilled and completed during the year ended December 31, 2022:

	Year Ended December 31, 2022			
	Drilled		Completed	
Area:	Gross	Net	Gross	Net
Midland Basin	197	183	213	197
Delaware Basin	43	40	42	39
Other	—	—	—	—
Total	240	223	255	236

As of December 31, 2022, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area:	Gross	Net	Gross	Net	Gross	Net
Midland Basin	3,028	2,864	2,084	1,936	5,112	4,800
Delaware Basin	39	35	687	643	726	678
Total	3,067	2,899	2,771	2,579	5,838	5,478

Productive Wells

As of December 31, 2022, we owned an interest in a total of 11,944 gross productive wells with an average unweighted 86% working interest in 6,489 gross (5,574 net) wells and an average 1.9% royalty interest in 5,455 additional wells. Through our subsidiary Viper, we own an average 3.8% net revenue interest in 8,260 of the total 11,944 gross productive wells. Productive wells consist of producing wells and wells capable of production, including natural gas wells 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, and net wells are the sum of our fractional working interests owned in gross wells.

The following table sets forth information regarding productive wells by basin as of December 31, 2022:

	Gross Wells			Net Wells		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
Midland Basin	9,170	32	9,202	4,850	11	4,861
Delaware Basin	2,358	272	2,630	683	27	710
Other	57	55	112	3	—	3
Total productive wells	11,585	359	11,944	5,536	38	5,574

Drilling Results

The following tables set forth information with respect to the number of wells drilled during the periods indicated by basin. Each of these wells was drilled in the Permian Basin of West Texas. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31, 2022					
	Midland Basin		**Delaware Basin**		**Total**	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	59	54	16	15	75	69
Dry	—	—	—	—	—	—
Exploratory:						
Productive	138	129	27	25	165	154
Dry	—	—	—	—	—	—
Total:						
Productive	197	183	43	40	240	223
Dry	—	—	—	—	—	—

	Year Ended December 31, 2021					
	Midland Basin		**Delaware Basin**		**Total**	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	33	30	7	7	40	37
Dry	—	—	—	—	—	—
Exploratory:						
Productive	142	135	34	31	176	166
Dry	—	—	—	—	—	—
Total:						
Productive	175	165	41	38	216	203
Dry	—	—	—	—	—	—

	Year Ended December 31, 2020					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	87	81	26	25	113	106
Dry	—	—	—	—	—	—
Exploratory:						
Productive	46	44	49	45	95	89
Dry	—	—	—	—	—	—
Total:						
Productive	133	125	75	70	208	195
Dry	—	—	—	—	—	—

As of December 31, 2022, we had 39 gross (33 net) operated wells in the process of drilling and 22 gross (20 net) wells in the process of completion or waiting on completion.

Acreage

The following table sets forth information as of December 31, 2022 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage		Total Acreage(2)	
Basin	Gross	Net	Gross	Net	Gross	Net
Midland	221,817	193,626	150,098	131,914	371,915	325,540
Delaware	102,464	78,195	99,160	72,524	201,624	150,719
Exploration	693	693	40,091	30,875	40,784	31,568
Conventional Permian	—	—	1,025	940	1,025	940
Total	324,974	272,514	290,374	236,253	615,348	508,767

(1) Does not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells.
(2) Does not include Viper's mineral interests but does include leasehold acres that we own underlying our mineral interests.

Undeveloped Acreage Expirations

As of December 31, 2022, the following gross and net undeveloped acres are set to expire over the next 5 years based on their contractual lease maturities unless (i) production is established within the spacing units covering the acreage or (ii) the lease is renewed or extended under continuous drilling provisions prior to the contractual expiration dates.

	Acres Expiring					
	Delaware		Midland		Total	
	Gross	Net	Gross	Net	Gross	Net
2023	112	93	450	372	562	465
2024	351	290	2,667	2,206	3,018	2,496
2025	150	124	2,980	2,464	3,130	2,588
2026	—	—	1,121	927	1,121	927
2027	—	—	—	—	—	—
Total	613	507	7,218	5,969	7,831	6,476

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. To the extent title opinions or other investigations reflect title defects impacting the development or operation of a producing property, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, an updated title review, or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Marketing and Customers

We typically sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2022, two purchasers each accounted for more than 10% of our revenue. For the year ended December 31, 2021, three purchasers each accounted for more than 10% of our revenue. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue. We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers. For additional information regarding our customer concentrations, see Note 3—Revenue from Contracts with Customers included in the notes to the consolidated financial statements included elsewhere in this Annual Report.

Delivery Commitments

Certain of our firm sales agreements include delivery commitments that specify the delivery of a fixed and determinable quantity of oil. We believe our current production and reserves are sufficient to fulfill these delivery commitments and we expect our reserves will continue to be the primary means of fulfilling our future commitments. However, these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate to satisfy our commitment. For additional information regarding commitments, see Note 15—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Competition

The oil and natural gas industry is intensely competitive, and in our upstream segment, we compete with other companies that may have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also 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 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. 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. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 15% to 35%, resulting in a net revenue interest to us generally ranging from 65% to 85%.

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 buyers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. In our exploration and production business, seasonal weather conditions, and lease stipulations can limit our 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 meeting our 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

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements. 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 our cost of doing business and, consequently, affects our profitability.

Environmental Matters

Our 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 our operations or related to our owned or operated facilities. 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 operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

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 are not necessary at this 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. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, 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 June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or the Corps, jointly promulgated final rules redefining the scope of waters protected under the CWA. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 rules, and then, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rule, and significantly reducing the waters subject to federal regulation under the CWA. On August 30, 2021, a federal court struck down the replacement rule and, on December 30, 2022, the EPA and the Corps published a final rule that would restore water protections that were in place prior to 2015. Meanwhile, in October 2022, the Supreme Court heard oral arguments in a case addressing the proper test for determining whether wetlands are "waters of the United States." As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the CWA. To the extent the rules 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. We believe we are in material compliance with the requirements of each of these laws.

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. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. 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. On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022, or the IRA, which includes 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. These incentives 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, 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 the offshore and onshore petroleum and natural gas production and gathering and boosting source categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025 and be set at $1,500 for 2026 and each year after. Calculation of the fee is based on 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 Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. Although the United States withdrew from the Paris Agreement effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which went into effect on February 19, 2021. 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. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the international climate commitments.

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.

In addition, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, by promoting divestment of fossil fuel equities and pressuring lenders to limit funding and insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions, such as the severe winter storms in the Permian Basin in February 2021, can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

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 former 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 November 15, 2021, the EPA published a proposed rule that would 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. On December 6, 2022, the EPA published a supplemental proposal to strengthen the emission reduction requirements, which would, among other things, expand leak detection requirements and tighten flaring restrictions. 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. We cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

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 OSHA 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 daily monitoring and reporting requirements for any new disposal well permitted in the Permian Basin. These restrictions on use of produced water, a moratorium on new produced water disposal wells, and additional monitoring and reporting requirements could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or pump it through the pipeline network or other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling and completion activity in the affected parts of the Permian Basin less economical and adversely impact our business, results of operations and financial condition.

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, state or local 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.

Endangered Species

The federal Endangered Species Act, or ESA, and analogous state laws restrict activities that may affect listed endangered or threatened species or their habitats. If endangered species, such as the recently listed lesser prairie chicken, are located in areas where we operate, our operations or any work performed related to them could be prohibited or delayed or expensive mitigation may be required. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in compliance with the ESA. However, the designation of previously unprotected species, such as dunes sagebrush lizard, in areas where we operate as threatened or endangered could result in the imposition of restrictions on our operations and consequently have a material adverse effect on our business.

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 our cost of doing business and, consequently, affects our profitability, 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. Our operations 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 we 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 you 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 where we operate. 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 of the natural gas we produce and the manner in which we market our production. 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," which include all of our sales of our own production. 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.

Our 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 we have a tariff on file with FERC to perform oil gathering service in interstate commerce. 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, including us, 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 us to the same extent as to our competitors.

Safety and Maintenance Regulation. In our midstream operations, we are subject to regulation by the U.S. Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including natural gas liquids and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

We are also subject to the Pipeline Safety Improvement Act of 2002. The Pipeline Safety Improvement Act establishes mandatory inspections for all United States crude oil and natural gas transportation pipelines and some gathering pipelines in high-consequence areas within ten years. DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

The Pipeline Safety and Job Creation Act, enacted in 2011, and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, also known as the PIPES Act, enacted in 2016, amended the HLPSA and increased safety regulation. The Pipeline Safety and Job Creation Act doubles the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1.0 million to $2.0 million for a related series of violations (now increased for inflation to $239,142 and $2,391,412, respectively), and provides that these maximum penalty caps do not apply to civil enforcement actions, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. The PIPES Act ensures that the PHMSA completes the Pipeline Safety and Job Creation Act requirements; reforms PHMSA to be a more dynamic, data-driven regulator; and closes gaps in federal standards.

PHMSA has undertaken rulemakings to address many areas of this legislation. For example, on October 1, 2019, PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside High Consequence Areas. The rules, once effective, also extend reporting requirements to certain previously unregulated gathering lines. Also, on November 15, 2021, PHMSA published a final rule extending reporting requirements to all onshore gas gathering operators and establishing a set of minimum safety requirements for certain gas gathering pipelines with large diameters and high operating pressures. Further, on August 24, 2022, PHMSA published a final rule strengthening integrity management requirements for onshore gas transmission lines, bolstering corrosion control standards and repair criteria, and imposing new requirements for inspections after extreme weather events. These requirements and related rule making proceedings, could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. In addition, any material penalties or fines issued to us under these or other statutes, rules, regulations or orders could have an adverse impact on our business, financial condition, results of operation and cash flow.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards, and many states have undertaken responsibility to enforce the federal standards. For example, on December 17, 2019, the Texas Railroad Commission adopted rules requiring that operators of gathering lines take 'appropriate' actions to fix safety hazards. We do not anticipate any significant problems in complying with applicable federal and state laws and regulations in Texas. Our gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. Moreover, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Rattler LLC and the entities in which it owns an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. Also, the Department of Homeland Security and other agencies such as the EPA continue to develop regulations concerning the security of industrial facilities, including crude oil and natural gas facilities. We are subject to a number of requirements and must prepare Federal Response Plans to comply. We must also prepare Risk Management Plans under the regulations promulgated by the EPA to implement the requirements under the CAA to prevent the accidental release of extremely hazardous substances. We have an internal program of inspection designed to monitor and enforce compliance with safeguard and security requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to safety and security.

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 we 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.

Operational Hazards and Insurance

The oil and natural gas industry involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for onshore property (oil lease property/production equipment) for selected locations, control of well protection for all wells, comprehensive general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverage.

Our insurance is subject to certain exclusions and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. See Item 1A. “Risk Factors–Risks Related to the

Oil and Natural Gas Industry and Our Business–Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits."

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third-party vendors to sign master service agreements in which they agree to indemnify us for property damage and injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

Human Capital

We have developed a culture grounded upon the solid foundation of our core values—leadership, integrity, excellence, people and teamwork—that are adhered to throughout our company. We set a high bar for all of our employees in terms of how they operate and interact, both within the office and out in the field. We challenge them to identify new ways to foster a better future for themselves and for us. Our board of directors, through its Safety, Sustainability and Corporate Responsibility Committee, which we refer to as the SS&CR Committee, provides an important oversight of our human capital management strategy, including diversity, equity and inclusion. In January 2022, the SS&CR Committee's charter was amended accordingly to include oversight of management of human capital as part of its ongoing responsibilities. The SS&CR Committee receives regular updates from our executive leadership, senior management and third-party consultants on human capital trends and other key human capital matters impacting our business.

As of December 31, 2022, we had 972 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also utilize independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full-time employees.

Diversity, Inclusion, Recruiting and Retention

Equal employment opportunity is one of our core tenets and, as such, our employment decisions are based on merit, qualifications, competencies and contributions. We actively seek to attract and retain an increasingly diverse workforce and continue to cultivate our respectful work environment. We value the perspectives, experiences and ideas contributed by our employees from a diverse range of ethnic, cultural and ideological backgrounds. Over 28% of our employees are women and over 33% of our employees self-identify as ethnic minorities as of December 31, 2022. We disclosed for the first time our 2021 Equal Employment Opportunity (EEO-1) data as of December 31, 2021 in our 2022 Corporate Sustainability Report in an effort to provide additional transparency into the Company's workforce demographics.

In 2022, we took various actions to increase the diversity of job applicants and expand our recruitment efforts, particularly in our college recruitment and internship programs. We collaborated with several student organizations to reinforce this inclusive initiative, which will continue in the future. In addition, we have focused on recruiting experienced hires to target and retain top industry talent. We have historically had a low annual attrition rate, representing approximately 13% in 2022, despite the challenging labor market and increased competition for talent impacted by the potential economic downturn and the high inflationary environment. We believe that our low attrition rate is in part a result of our corporate culture focused on diversity and inclusion, teamwork and commitment to employee development and career advancement discussed in more detail below.

Health and Safety

Protecting employees, the public and the environment is a top priority in our operations and in the way we manage our assets. We are focused on minimizing the risk of workplace incidents and preparing for emergencies as an ingrained element of our corporate responsibility. We also strive to comply with all applicable health, safety and environmental standards, laws and regulations.

We have committed to reduce injuries and fatalities in our business and are focused on safety culture improvements, safety leadership actions and human performance principles. We are requiring our operational employees and independent contractors and their employees to go through orientation and training aligned with the International Association of Oil and

Gas Producers Life Saving Rules, a program that also meets the operational safety requirements adopted by the American Petroleum Institute. We also involve employees from all operational levels in our safety program to provide input and suggested improvements to the overall safety program, recommend preventative measures based on reviewing vehicle and personnel incidents, safety and environmental audits at operational locations and participate in the audit and oversight of the Diamondback Hazard Communication Program.

From 2018 through 2022, we had no employee work-related fatalities. Our employee OSHA recordable cases, comprising work-related injuries and illnesses that require medical treatment beyond first aid, totaled six in 2022, up from two in 2021. Our employee total recordable incident rate (TRIR) was 0.68 in 2022 up from 0.25 in 2021 and lost-time incident rate (LTIR) was 0.23 in 2022 up from 0.12 in 2021. At December 31, 2022, we have a short term goal of maintaining an employee TRIR of 0.25 or less.

Training and Development

We support employees in pursuing training opportunities to expand their professional skills. Our internal course offerings in 2022 included a wide array of topics in addition to extensive safety and other compliance training sessions. Additionally, our people undergo training and education each year on regulatory compliance, industry standards and innovative opportunities to effectively manage the challenges of developing our resources. We have also implemented development programs that are designed to build leadership capabilities at all levels.

Our Facilities

Our corporate headquarters is located at the Fasken Center in Midland, Texas. We also lease additional office space in Midland, Texas, Oklahoma City, Oklahoma and Denver, Colorado.

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 Investor Relations page of our website at www.diamondbackenergy.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 described in Item 1. “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.” 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.

The following is a summary of the principal risks that could adversely affect our business, operations and financial results:

Risks Related to the Oil and Natural Gas Industry and Our Business

- Market conditions and particularly volatility in prices for oil and natural gas may continue to adversely affect our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves.
- Our business and operations have been and will likely continue to be adversely affected by the war in Ukraine, COVID-19 pandemic and volatility in the oil and natural gas markets.
- 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.
- 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.
- Climate change-related regulations, policies and initiatives may have other adverse effects, such as a greater potential for governmental investigations or litigation.

- We may be unable to obtain needed capital or financing on satisfactory terms or at all to fund our acquisitions or development activities, which could lead to a loss of properties and a decline in our oil and natural gas reserves and future production.
- Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings, and title defects in the properties in which we invest may lead to losses.
- Our identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- If production from our Permian Basin acreage decreases, we may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contract, which may adversely affect our operations.
- The inability of one or more of our customers to meet their obligations, or loss of one or more of our significant purchasers, may adversely affect our financial results.
- Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.
- Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- We are vulnerable to risks associated with our primary operations concentrated in a single geographic area.
- If transportation or other facilities, certain of which we do not control, or rigs, equipment, raw materials, oil services or personnel are unavailable, our operations could be interrupted and our revenues reduced.
- Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive and may impose restrictions on our operations.
- U.S. tax legislation, including recently adopted IRA, may negatively affect our business, results of operations, financial condition and cash flow.
- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.
- A terrorist attack or armed conflict could harm our business and could adversely affect our business.
- A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Risks Related to Our Indebtedness

- Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our indebtedness, and we and our subsidiaries may be able to incur substantial additional indebtedness in the future.
- Implementing our capital programs may require, under some circumstances, an increase in our total leverage through additional debt issuances, and any significant reduction in availability under our revolving credit facility or inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.
- Restrictive covenants in certain of our existing and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.
- We depend on our subsidiaries for dividends, distributions and other payments.
- 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.
- Borrowings under our and Viper LLC's revolving credit facilities expose us to interest rate risk.

Risks Related to Our Common Stock

- The corporate opportunity provisions in our certificate of incorporation could enable affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.
- If the price of our common stock fluctuates significantly, an investment in us could lose value.
- The declaration of dividends and any repurchases of our common stock are each within the discretion of our board of directors, and there is no guarantee that we will pay any dividends on or repurchases of our common stock in the future or at levels anticipated by our stockholders.
- A change of control could limit our use of net operating losses.
- If our operating results do not meet expectations of securities or industry analysts, our stock price could decline.
- We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.
- Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

Risks Related to the Oil and Natural Gas Industry and 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, production and the present value of our estimated reserves.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including the domestic and foreign supply of oil and natural gas; the level of prices and expectations about future prices of oil and natural gas; the level of global oil and natural gas exploration and production; the cost of exploring for, developing, producing and delivering oil and natural gas; the price and quantity of foreign imports; political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia; the potential impact of the war in Ukraine on the global energy markets; the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East; the ability of members of the OPEC+ to agree to and maintain oil price and production controls; speculative trading in crude oil and natural gas derivative contracts; the level of consumer product demand; extreme weather conditions and other natural disasters; risks associated with operating drilling rigs; technological advances affecting energy consumption; the price and availability of alternative fuels; domestic and foreign governmental regulations and taxes, including the Biden Administration’s energy and environmental policies; global or national health concerns, including the outbreak of pandemic or contagious disease, such as COVID-19 and its variants; the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and overall domestic and global economic conditions. Our results of operations may also be 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 operate.

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. During 2022, 2021 and 2020, NYMEX WTI prices ranged from $(37.63) to $123.70 per Bbl and the NYMEX Henry Hub price of natural gas ranged from $1.48 to $9.68 per MMBtu. If the prices of oil and natural gas decline, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected.

We cannot predict the impact of the ongoing military war between Russia and Ukraine and the related humanitarian crisis on the global economy, energy markets, geopolitical stability and our business.

Our leasehold acreage is located primarily in the Permian Basin in West Texas. However, the broader consequences of the war in Ukraine, which may include further sanctions, embargoes, supply chain disruptions, regional instability and geopolitical shifts, may have adverse effects on global macroeconomic conditions, increase volatility in the price and demand for oil and natural gas, increase exposure to cyberattacks, cause disruptions in global supply chains, increase foreign currency fluctuations, cause constraints or disruption in the capital markets and limit sources of liquidity. We cannot predict the extent of the war’s effect on our business and results of operations as well as on the global economy and energy markets.

In prior periods, our business and operations were adversely impacted by the COVID-19 pandemic and volatility in the oil and natural gas markets, compounded by the global effects of the war in Ukraine, and we may experience such adverse effects in future periods. If commodity prices decrease, our production, estimates of proved reserves and liquidity may be adversely affected.

The COVID-19 pandemic, combined with the global effects of the war in Ukraine, contributed to economic and pricing volatility that adversely impacted in prior periods, and may in the future adversely impact, our business and our industry. Despite the recovery and overall strength in demand and pricing for oil in 2022, using excess cash flow for debt repayment and/or returning capital to our stockholders rather than expanding our drilling program. We intend to continue exercising capital discipline and expect to maintain flat oil production in 2023 at the fourth quarter 2022 level, excluding production from recent acquisitions. We cannot reasonably predict whether production levels will remain at current levels or the full extent of the events above and any subsequent recovery may have on our industry and our business.

Due to the improvement in commodity pricing environment and industry conditions, we did not record any impairments in 2022. 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. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could limit our liquidity and ability to conduct additional exploration and development activities.

The COVID-19 pandemic continues to present operational, health, labor, logistics and other challenges, and it is difficult to assess the ultimate impact of the COVID-19 pandemic on our business, financial condition and cash flows.

There continue to be many variables and uncertainties regarding the COVID-19 pandemic, including the emergence, contagiousness and threat of new and different strains of the virus and their severity; the effectiveness of current treatments and vaccines against the virus or its new strains; any travel restrictions, business closures and other measures that are or may be imposed in affected areas or countries by governmental authorities; disruptions in the supply chain; competitive labor market; logistics costs; remote working arrangements, social distancing guidelines and other COVID-19-related challenges. Further, there remain increased risks of cyberattacks on information technology systems used in a remote working environment; increased privacy-related risks due to processing health-related personal information; absence of workforce due to illness; the impact of the pandemic on any of our contractual counterparties; and other factors that are currently unknown or considered immaterial. It is difficult to assess the ultimate impact of the COVID-19 pandemic on our business, financial condition and cash flows.

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 commodity price derivatives, including swaps, basis swaps, swaptions, roll hedges, costless collars, puts and basis puts, to reduce price volatility associated with certain of our oil, natural gas liquids and natural gas sales. Currently, we have hedged a portion of our estimated 2023 and 2024 production. To the extent that the prices of oil, natural gas liquids and natural gas remain at current levels or decline further, we may not be able to economically hedge additional future production at the same level as our current commodity price derivatives, and our results of operations and financial condition may be negatively impacted. While these commodity price derivatives are intended to mitigate risk from commodity price volatility, 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.

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. We do not require collateral from our counterparties.

For additional information regarding our outstanding derivative contracts as of December 31, 2022, see Note 12—Derivatives to our consolidated financial statements included elsewhere in this report, 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.

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:

- 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;
- 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);
- 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
- 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.

If any of these developments reduce the desirability of participating in the oilfield services, midstream or downstream portions of the oil and gas industry, then these developments may also reduce the availability to us of necessary third-party services and facilities that we rely on, which could increase our operational costs and adversely affect our ability to explore for, produce, transport and process oil and natural gas and successfully carry out our business and financial strategy. 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.

On August 16, 2022, President Biden signed into law the IRA, which includes 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. These incentives 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. In addition, the IRA imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge, which could increase our operating costs and thereby adversely impact our business, financial condition and cash flows.

In addition to potentially reducing demand for our oil and natural gas and potentially reducing the availability of oilfield services and midstream and downstream customers, any of these developments may also 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, a number of prominent investors have publicly announced their intention to no longer invest in the oil and gas sector in response to concerns related to climate change, and other financial institutions and investors may decide to do likewise in the future. 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 significantly increased cost.

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

Continuing political and social concerns relating to climate change may result in significant litigation and related expenses.

Increasing attention to global climate change has resulted in increased investor attention and an increased risk of public and private litigation, which could increase our costs or otherwise adversely affect us. For example, shareholder activism has recently been increasing in our industry, and shareholders may attempt to effect changes to our business or governance to deal with climate change-related issues, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise, which may result in significant management distraction and potentially significant expense.

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, 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 in our operations, and increases to our operating expenses, which in turn could have an adverse effect on our business, financial condition and results of operations.

Our targets related to sustainability and emissions reduction initiatives, including our public statements and disclosures regarding them, may expose us to numerous risks.

We have developed, and will continue to develop, targets related to our ESG initiatives, including our emissions reduction targets and strategy. Statements in this and other reports we file with the SEC and other public statements related to these initiatives reflect our current plans and expectations and are not a guarantee the targets will be achieved or achieved on the currently anticipated timeline. Our ability to achieve our ESG targets, including emissions reductions, is subject to numerous factors and conditions, some of which are outside of our control, and failure to achieve our announced targets or comply with ethical, environmental or other standards, including reporting standards, may expose us to government enforcement actions or private litigation and adversely impact our business. Further, our continuing efforts to research, establish, accomplish and accurately report on these targets may create additional operational risks and expenses and expose us to reputational, legal and other risks.

Investor and regulatory focus on ESG matters continues to increase. If our ESG initiatives do not meet our investors' or other stakeholders' evolving expectations and standards, investment in our stock may be viewed as less attractive and our reputation, contractual, employment and other business relationships may be adversely impacted.

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 flows.

A significant portion of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

A significant portion of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive and to maintain the production in paying quantities, and if we are unsuccessful in drilling such wells and maintaining such production, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our development and exploration operations and our ability to complete acquisitions require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. In 2022, our total capital expenditures, including expenditures for drilling, completion, infrastructure and additions to midstream assets, were approximately $1.9 billion. Our 2023 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $2.50 billion to $2.70 billion, representing an increase of 37% from our 2022 capital expenditures. Since completing our initial public offering in October 2012, we have financed capital expenditures primarily with borrowings under our revolving credit facility, cash generated by operations and the net proceeds from public offerings of our common stock and our senior notes.

We intend to finance our future capital expenditures with cash flow from operations, while future acquisitions may also be funded from operations as well as proceeds from offerings of our debt and equity securities and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including our proved reserves; the volume of oil and natural gas we are able to produce from existing wells; the prices at which our oil and natural gas are sold; our ability to acquire, locate and produce economically new reserves; and our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2023 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements or our costs of capital increase, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. If we are unable to replace our current production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings and slow our growth.

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 or environmental issues, 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. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. 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. If these acquisitions include geographic regions in which we do not currently operate, we could be subject to unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. 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 integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses 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 these factors could have a material adverse effect on our financial condition and results of operations. Our financial position and results of operations may also fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, 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 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, we will suffer a financial loss.

Our identified potential drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs.

As of December 31, 2022, we have approximately 8,276 gross (6,055 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $50.00 per Bbl WTI. As of December 31, 2022, only 703 of our gross identified economic potential horizontal drilling locations were attributed to proved reserves. These drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, unusual or unexpected geological formations, title problems, facility or equipment malfunctions, unexpected operational events, inclement weather, environmental and other regulatory requirements and approvals, oil and natural gas prices, costs, drilling results and the availability of water. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. In addition, as of December 31, 2022, we have identified approximately 2,148 horizontal drilling locations in intervals in which we have drilled very few or no wells, which are necessarily more speculative and based on results from other operators whose acreage may not be consistent with ours. We cannot predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. Through December 31, 2022, we are the operator of, have participated in, or have acquired working interest in a total of 3,254 horizontal producing wells completed on our acreage. We cannot assure you that the analogies we draw from available data from these or other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Any non-renewal or other loss of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.

If production from our Permian Basin acreage decreases due to decreased developmental activities, production related difficulties or otherwise, we may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contracts, which will result in deficiency payments to the counterparty and may have an adverse effect on our operations.

We are a party to long-term crude oil agreements under which, subject to certain terms and conditions, we are obligated to deliver specified quantities of oil to our counterparties. Our maximum delivery obligation under these agreements varies for different periods and depends in some cases upon certain conditions beyond our control. If production from our Permian Basin acreage decreases due to reduced developmental activities, as a result of the low commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under our oil purchase agreements, which may result in deficiency payments to certain counterparties or a default under such agreements and may have an adverse effect on our company.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through receivables from joint interest owners on properties we operate (approximately $93 million at December 31, 2022) and receivables from purchasers of our oil and natural gas production (approximately $618 million at December 31, 2022). Joint interest receivables arise from billing entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells.

We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. See "Item 1 and 2. Business and Properties—Oil and Natural Gas Production Prices and Production Costs—Marketing and Customers" for additional information regarding these customers. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic and other conditions. We do not require our customers to post collateral. Under certain circumstances, the revenue due to them can be offset by any unpaid receivables. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results.

Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment.

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. We use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.

No impairments were recorded on our proved oil and natural gas properties for the years ended December 31, 2022 and 2021. An impairment of $6.0 billion was recorded for our proved oil and natural gas properties for the year ended December 31, 2020. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates—Method of Accounting for Oil and Natural Gas Properties." If the prices of oil and natural gas decline, we may be required to further write-down the value of our oil and natural gas properties in the future, which could negatively affect our results of operations.

Our estimated reserves and EURs 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. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. The EURs for our horizontal wells are based on management's internal estimates. 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 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. The reserve estimates represent our net revenue interest in our properties.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves.

The standardized measure of our estimated proved reserves are not necessarily the same as the current market value of our estimated proved oil reserves.

The present value of future net cash flow from our proved reserves, or standardized measure may not represent the current market value of our estimated proved oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, “Extractive Activities—Oil and Gas,” may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

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

Approximately 31% of our total estimated proved reserves as of December 31, 2022, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling and completion operations. The reserve data included in the reserve reports of our independent petroleum engineers assume 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 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.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks (including weather-related risks) associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are currently geographically 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, 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, and extreme weather conditions and their adverse impact on production volumes, availability of electrical power, road accessibility and transportation facilities.

Extreme regional weather events may occur that can affect our 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 (including potentially our production) to be curtailed or shut in or (in the case of natural gas) flared. Further, any increase in flaring of our natural gas production due to weather-related events or otherwise could make it difficult for us to achieve our publicly-announced sustainability and emissions reduction targets, which could expose us to reputational risks and adversely impact our 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 our production volumes (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 portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

In addition to the geographic concentration of our producing properties described above, as of December 31, 2022, most of our proved reserves are concentrated in the Wolfberry 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 us to permanently or temporarily shut-in all of our wells within a field.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See "Item 1 and 2. Business and Properties—Oil and Natural Gas Production Prices and Production Costs—Marketing and Customers" for additional information regarding these customers. The loss of one or more of these customers, and our inability to sell our production to other customers on terms we consider acceptable, could materially and adversely affect our business, financial condition, results of operations and cash flow.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing rigs, and the operators of those rigs may choose to cease providing services to us. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

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

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. Over the past several years, Texas has experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, or we are unable to effectively utilize flowback water, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Recent regulatory restrictions on the disposal of produced water and additional monitoring and reporting requirements related to existing and additional monitoring new produced water disposal wells in the Permian Basin to stem rising seismic activity and earthquakes could increase our operating costs and adversely impact our business, results of operations and financial condition.

In September 2021, the Texas Railroad Commission curtailed the amount of produced water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin, and has since indefinitely suspended some permits there and expanded the restrictions to other areas. These actions were taken in an effort to control induced seismic activity and recent increases in earthquakes in the Permian Basin, which have been linked by the U.S. and local seismologists to wastewater disposal in oil fields. The Texas Railroad Commission has since adopted rules governing the permitting or repermitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. These restrictions on the disposal of produced water and additional monitoring and reporting requirements related to existing and new disposal of produced water and additional monitoring and reporting requirements related to existing and new produced water disposal wells could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or dispose of it by other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers 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, results of operations and financial condition.

In response to recent seismic activity in the Midland Basin over the past couple of years, the Texas Railroad Commission has pursued a series of actions commencing in the latter half of 2021, including suspending deep disposal activity and curtailing certain shallow disposal activities in the areas of heightened seismic activity. Such restrictions have not had a material impact on our operations to date, but further restrictions across the basin as a result of more stringent regulations or legal directives, potential litigation or other developments could increase our operating costs and materially impact our ability to dispose of produced water, which could have a material adverse effect on our business, results of operations and financial condition.

We have incurred losses from operations during certain periods since our inception and may do so in the future.

Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from our operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve developing and utilizing the latest drilling and completion techniques. Risks that we face while drilling include, but are not limited to, the following:

- spacing of wells to maximize economic return;
- landing our well bore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the well bore; and
- being able to run tools and other equipment consistently through the horizontal well bore.

Risks that we face while completing our wells include, but are not limited to, being able to:

- fracture stimulate the planned number of stages;
- run tools the entire length of the well bore during completion operations;
- successfully clean out the well bore after completion of the final fracture stimulation stage; and
- prevent unintentional communication with other wells.

Furthermore, certain of the new techniques we are adopting, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering line, which interconnects with third party pipelines. Our natural gas production is generally transported by our gathering lines from the wellhead to an interconnection point with a purchaser or into a third-party gathering system. We do not control third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. For example, on certain occasions we have experienced high line pressure at our tank batteries with occasional flaring due to the inability of the gas gathering systems in the areas in which we operate to support the increased production of natural gas in the Permian Basin. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Further, these laws and regulations imposed strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. In addition, federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Even if federal regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term, and at the state and local levels. See “Item 1 and 2. Business and Properties—Regulation” for a detailed description of certain laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered, such as the recent designation of lesser prairie chickens in southwestern Texas as endangered, could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act established federal oversight of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act required the Commodity Futures Trading Commission (CFTC), the SEC, and certain federal regulators of financial institutions (Prudential Regulators), to adopt rules or regulations implementing the Dodd-Frank Act. The Dodd-Frank Act established margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued a number of rules, including rules requiring clearing of certain swaps through registered clearing facilities (Mandatory Clearing Rule), requiring the posting of collateral for uncleared swaps (Margin Rule) and imposing position limits (Position Limit Rule). There are exceptions, subject to meeting certain filing, recordkeeping and reporting requirements, to the Mandatory Clearing Rule, the Margin Rule and the Position Limit Rule.

We qualify for the “end user” exception to the Mandatory Clearing Rule and the “non-financial end user” exception to the Margin Rule and we believe that the majority, if not all, of our hedging activities qualify for the “bona fide hedging transaction or position” exception to the Position Limit Rule. We intend to satisfy the applicable filing, recordkeeping and reporting requirements to use these exceptions, so we do not expect to be directly affected by any of such rules. However, most if not all of our swap counterparties will be subject to mandatory clearing and collateral requirements in connection with their hedging activities with other counterparties that do not qualify for exceptions to these rules, which could significantly increase the cost of our derivative contracts or reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business.

In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (collectively, Foreign Regulations), which may apply to our transactions with counterparties subject to such Foreign Regulations (Foreign Counterparties). The Foreign Regulations, the Dodd-Frank Act, the rules which have been adopted and not vacated and other regulations could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act, the Foreign Regulations or other regulations, our results of operations and cash flows may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

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 at least $1 billion average adjusted pre-tax net income on their consolidated financial statements) as well as an excise tax of 1% on the fair market value of certain public company stock repurchases for tax years beginning after December 31, 2022. If we are or become subject to CAMT, our cash obligations for U.S. federal income taxes could be significantly accelerated. To the extent the 1% excise tax applies to repurchases of shares under our common stock 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 guidance on how the 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.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Our operations and drilling activity are concentrated in the Permian Basin in West Texas, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could lead to a reduction in production volumes. Any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our business, financial condition and results of operations.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team, including our Chief Executive Officer, Travis D. Stice, could disrupt our operations. We do not have employment agreements with our executives and may not be able to assure their retention. Further, we do not maintain “key person” life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks and ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations.

We endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under our agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors’ equipment while in their control and (ii) we generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we generally agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operations.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are part of our operations, we maintain insurance to protect against claims made for bodily injury and property damage, and that insurance includes coverage for clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the “occurrence” to our insurance company within the time frame required under our insurance policy. We have limited coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we 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 financial position, results of operations and cash flows.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We own interests in certain pipeline projects and other joint ventures, and we may in the future enter into additional joint ventures, and our control of such entities is limited by provisions of the governing documents of such entities and by our percentage ownership in such entities.

We have ownership interests in several joint ventures, including the EPIC, Wink to Webster, BANGL, WTG and OMOG joint ventures, and we may enter into other joint venture arrangements in the future. While we own equity interests and have certain voting rights with respect to our joint ventures, we do not act as operator of or control our joint ventures (including our 43% interest in the OMOG joint venture), each of which is operated by another joint venture partner. We have limited ability to influence the business decisions of these entities, and it may therefore be difficult or impossible for us to cause the joint venture to take actions that we believe would be in our or the relevant joint venture’s best interests. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may not control. In addition, our joint venture partners may not satisfy their financial obligations to the joint venture and may have economic, business or legal interests or goals that are inconsistent with ours, or those of the joint venture.

We are also unable to control the amount of cash we receive from the operation of these entities. Further, certain of these joint ventures have incurred substantial debt and servicing such debt or complying with debt covenants may limit the ability of the joint ventures to make distributions to us and the other joint venture partners. These joint ventures also have internal control environments independent of our oversight and review. If our joint venture partners have control deficiencies in their accounting or financial reporting environments, it may result in inaccuracies in the reporting for our percentage of the financial results for the joint venture.

We may not own in fee the land on which our pipelines and facilities are located, which could result in disruptions to our midstream services.

The majority of the land on which our midstream systems have been constructed is owned by third parties or held by surface use agreements, rights-of-way, surface leases or other easement rights, which may limit or restrict our rights or access to or use of the surface estates. Accommodating these competing rights of the surface owners may adversely affect our midstream operations. In addition, we are subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way, surface leases or other easement rights or if such usage rights lapse or terminate. We may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew rights-of-way, surface leases or other easement rights or otherwise, could have an adverse effect on our business, financial condition, results of operations and cash flow.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our operations depend heavily 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 heavily dependent on electrical power, internet and telecommunications infrastructure and our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. 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 operate 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.

As an exploration and production company, we rely extensively on information technology systems, including internally developed software, data hosting platforms, real-time data acquisition systems, third-party software, cloud services and other internally or externally hosted hardware and software platforms, to (i) estimate our oil and natural gas reserves, (ii) process and record financial and operating data, (iii) process and analyze all stages of our business operations, including exploration, drilling, completions, production, transportation, pipelines and other related activities and (iv) communicate with our employees and vendors, suppliers and other third parties. Further, our reliance on technology has increased due to the increased use of personal devices, remote communications and work-from-home or hybrid work practices that evolved in response to the COVID-19 pandemic.

Our systems and networks, and those of our 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 employees, insiders or others with authorized access; cyber or phishing-attacks; ransomware; attempts to gain unauthorized access to our data and systems; and other electronic security breaches. If any of these security breaches were to occur, we could suffer disruptions to our normal operations, including our exploration, completion, production and corporate functions, which could materially and adversely affect us in a variety of ways, including, but not limited to, the following:

- unauthorized access to, and release of, our business data, reserves information, strategic information or other sensitive or proprietary information, which could have a material and adverse effect on our ability to compete for oil and gas resources, or reduce our competitive advantage over other companies;
- data corruption, communication interruption, or other operational disruptions during our drilling activities, which could result in our failure to reach the intended target or a drilling incident;
- data corruption or operational disruptions of our production-related infrastructure, which could result in loss of production or accidental discharges;
- unauthorized access to, and release of, personal information of our employees, vendors, service providers or other third parties, which could expose us to allegations that we did not sufficiently protect such information;

- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt our operations;
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or other facilities, which could result in reduced demand for our production or delay or prevent us from transporting and marketing our production, in either case resulting in a loss of revenues;
- a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- a deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory enforcement actions, fines or penalties;
- a cybersecurity attack on a communications network or power grid, which could cause operational disruptions resulting in a loss of revenues; and
- a cybersecurity attack on our automated and surveillance systems, which could cause a loss of production and potential environmental hazards.

We have implemented and invested in, and will continue to implement and invest in, controls, procedures and protections (including internal and external personnel) that are designed to protect our systems, identify and remediate on a regular basis vulnerabilities in our systems and related infrastructure and monitor and mitigate the risk of data loss and other cybersecurity threat. Such measures, however, cannot entirely eliminate cybersecurity threats and the controls, procedures and protections we have implemented and invested in may prove to be ineffective. We maintain specialized insurance for possible liability resulting from a cyberattack on our assets, however, we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we 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 financial position, results of operations and cash flows.

Risks Related to Our Indebtedness

References in this section to “us, “we” or “our” shall mean Diamondback Energy, Inc. and Diamondback E&P LLC, collectively, unless otherwise specified.

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

We have historically relied on availability under our revolving credit facility to fund a portion of our capital expenditures. We expect that we will continue to fund a portion of our capital expenditures with borrowings under the revolving credit facility, cash flow from operations and the proceeds from debt and equity offerings. In the past, we have created availability under the revolving credit facility by repaying outstanding borrowings with the proceeds from debt or equity offerings. We cannot assure you that we will choose to or be able to access the capital markets to repay any such future borrowings. Instead, we may be required or choose to finance our capital expenditures through additional debt issuances, which would increase our total amount of debt outstanding. 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 limit our ability to fund our drilling activities and acquisitions or otherwise finance the capital expenditures necessary to replace our reserves.

Restrictive covenants in certain of our existing and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.

Certain of our debt instruments contain, and the terms of any future indebtedness may contain, restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness; make certain investments; create liens; sell or transfer assets; issue preferred stock; merge or consolidate with another entity; pay dividends or make other distributions; create unrestricted subsidiaries; and engage in transactions with affiliates. A breach of any of these restrictive covenants could result in default under the applicable debt instrument.

Under our revolving credit facility we are allowed, among other things, to designate one or more of our subsidiaries as “unrestricted subsidiaries” that are not subject to certain restrictions contained in the revolving credit facility. Under our revolving credit facility, we designated Viper, Viper’s General Partner, Viper’s subsidiary, Rattler, Rattler’s GP and Rattler’s subsidiaries as unrestricted subsidiaries, and upon such designation, they were automatically released from any and all obligations under the revolving credit facility, including the related guaranty. Further Viper, Viper’s General Partner, Viper’s subsidiaries, Rattler, Rattler's GP and Rattler's subsidiaries are designated as unrestricted subsidiaries under the indentures governing our outstanding Guaranteed Senior Notes.

We and our subsidiaries may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants and financial covenants contained in our and our subsidiaries' debt instruments. As an example, our revolving credit facility requires us to maintain a total net debt to capitalization ratio. The requirement that we and our subsidiaries comply with these provisions may materially adversely affect our and our subsidiaries 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.

If a default occurs under our revolving credit facility, the lenders thereunder 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 our senior notes. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If the indebtedness under our revolving credit facility and our senior notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Our indebtedness is structurally subordinated to the indebtedness and other liabilities of our subsidiaries, and our obligations are not obligations of any of our subsidiaries.

Our senior indebtedness obligations are obligations exclusively of Diamondback Energy, Inc. and Diamondback E&P LLC, and not of any of our other subsidiaries. None of our other subsidiaries is a guarantor of our senior indebtedness. Any assets of those subsidiaries will not be directly available to satisfy the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes. Except to the extent we are a creditor with recognized claims against our subsidiaries, all claims of creditors of our subsidiaries will have priority over our equity interests in such subsidiaries (and therefore the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes) with respect to the assets of such subsidiaries. Even if we are recognized as a creditor of one or more of our subsidiaries, our claims would still be effectively subordinated to any security interests in the assets of any such subsidiary and to any indebtedness or other liabilities of any such subsidiary senior to our claims. Consequently, our senior indebtedness will be structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries (other than Diamondback E&P LLC) and any subsidiaries that we may in the future acquire or establish. For additional information regarding our subsidiaries' outstanding debt as of December 31, 2022, see Note 8—Debt to our consolidated financial statements included elsewhere in this Annual Report.

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, including our senior notes, depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. If we are unable to generate sufficient cash flow to service our debt, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional equity 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 or operations to attempt to meet our debt service and other obligations. 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.

We depend on our subsidiaries for dividends, distributions and other payments.

We depend on our subsidiaries for dividends, distributions and other payments. We are a legal entity separate and distinct from our operating subsidiaries. There are statutory and regulatory limitations on the payment of dividends or distributions by certain of our subsidiaries to us. If our subsidiaries are unable to make dividend or distribution payments to us and sufficient cash or liquidity is not otherwise available, we may not be able to make dividend payments to our stockholders or principal and interest payments on our outstanding indebtedness.

We and our subsidiaries may still be able to incur substantial additional indebtedness in the future, which could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our and our subsidiaries' revolving credit facilities and the indentures restrict, but in each case do not completely prohibit, us from doing so. Further, the indentures governing our and our subsidiaries' notes allow us to issue additional notes, incur certain other additional debt and to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to the senior notes. In addition, the indentures governing the senior notes do not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

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 borrowing costs.

Borrowings under our and Viper LLC's revolving credit facilities expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our and Viper LLC's revolving credit facilities. The terms of our and Viper LLC's revolving credit facilities provide for interest on borrowings at a floating rate equal to an alternate base rate tied to the secured overnight financing rate ("SOFR"). SOFR tends to fluctuate based on multiple factors, including general short-term interest rates, rates set by the U.S. Federal Reserve, which may increase further in 2023, and other central banks and general economic conditions. From time to time, we use interest rate swaps to reduce interest rate exposure with respect to our fixed and/or floating rate debt. The weighted average interest rate on borrowings under our revolving credit facility was 3.91% during the year ended December 31, 2022. Viper LLC's weighted average interest rate on borrowings from its revolving credit facility was 4.22% during the year ended December 31, 2022. 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 Related to Our Common Stock

The corporate opportunity provisions in our certificate of incorporation could enable affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things: permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested; permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

If the price of our common stock fluctuates significantly, your investment could lose value.

Although our common stock is listed on the Nasdaq Global Select Market, we cannot assure you that an active public market will continue for our common stock. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. Furthermore, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including our quarterly or annual operating results; changes in our earnings estimates; investment recommendations by securities analysts following our business or our industry; additions or departures of key personnel; changes in the business, earnings estimates or market perceptions of our competitors; our failure to achieve operating results consistent with securities analysts' projections; changes in industry, general market or economic conditions; and announcements of legislative or regulatory changes.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

The declaration of base and variable dividends and any repurchases of our common stock are each within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.

On February 13, 2018, we initiated payment of quarterly cash dividends on our common stock payable beginning with the first quarter of 2018. The decision to pay any future base and variable dividends, however, is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, whether base or variable, or declare dividends at rates that are less than currently anticipated, either of which could reduce returns to our stockholders.

In September 2021, our board of directors approved a stock repurchase program to acquire up to $2.0 billion of our outstanding common stock, and on July 28, 2022, approved an increase in the repurchase program to $4.0 billion. We may be limited in our ability to repurchase shares of our common stock by various governmental laws, rules and regulations which prevent us from purchasing our common stock during periods when we are in possession of material non-public information. Through December 31, 2022, approximately $1.5 billion has been repurchased through the repurchase program. Even though this program is in place, we may not repurchase any shares through the program and any such repurchases are completely within the discretion of our board of directors. In addition, the stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time. Any elimination of, or reduction in, the Company's base or variable dividend or common stock repurchase program could adversely affect the total return of an investment in and have a material adverse effect on the market price of our common stock.

In June 2022, our board of directors approved an increase to our return of capital commitment to at least 75% of free cash flow to be distributed quarterly to our stockholders in the primary form of a base dividend with additional return of capital expected to be in the form of a variable dividend and through our stock repurchase program. The amount of cash available to return to our stockholders, if any, can vary significantly from quarter to quarter for a number of reasons, including, commodity prices, liquidity, debt levels, capital resources and other factors. The price of our common stock may deteriorate if we are unable to meet investor expectations with respect to the timing and amount of our return of capital commitment to our stockholders, and such deterioration may be material.

A change of control could limit our use of net operating losses and certain other tax attributes.

Under Section 382 of the Code, a corporation that experiences an "ownership change" (as defined in the Code) may be subject to limitations on its ability to offset taxable income arising after the ownership change with net operating losses ("NOLs") or tax credits generated prior to the ownership change. In general, an ownership change occurs if there is a cumulative increase in the ownership of a corporation's stock totaling more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. An ownership change would establish an annual limitation on the amount of a corporation's pre-change NOLs or tax credits that could be utilized to offset taxable income in any future taxable year. The amount of the limitation is generally equal to the value of the corporation's stock immediately prior to the ownership change multiplied by an interest rate, referred to as the long-term tax-exempt rate, periodically promulgated by the IRS. This limitation, however, may be significantly increased if there is "net unrealized built-in gain" in the assets of the corporation undergoing the ownership change.

As of December 31, 2022, we had an NOL carryforward of approximately $1.3 billion and tax credits of $4 million for federal income tax purposes. As a result of ownership changes for Diamondback Energy, Inc., QEP and Rattler, which occurred in connection with the acquisition of QEP and the Rattler Merger, our NOLs and other carryforwards, including those acquired from QEP and Rattler, are subject to an annual limitation under Section 382 of the Code. However, we have determined that our fair market value and our net unrealized built-in gain position resulted in a significant increase in our Section 382 limits. Accordingly, we believe that the application of Section 382 as a result of these ownership changes will not have an adverse effect on our ability to utilize our NOLs and credits.

Future changes in our stock ownership, however, could result in an additional ownership change under Section 382 of the Code. Any such ownership change may limit our ability to offset taxable income arising after such an ownership change with NOLs or other tax attributes generated prior to such an ownership change, possibly substantially.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrade our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders; limitations on the ability of our stockholders to call a special meeting and act by written consent; the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws; the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors; the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various routine legal proceedings, disputes and claims arising in the ordinary course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, results of operations or cash flows. For additional information regarding environmental matters, see Note 15—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Annual 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

Our common stock is listed on the Nasdaq Global Select Market under the symbol "FANG". There were 5,321 holders of record of our common stock on February 17, 2023.

Dividend Policy

Future base and variable dividends are at the discretion of our board of directors, and the board of directors may change the dividend amount from time to time based on the Company's outlook for commodity prices, liquidity, debt levels, capital resources, free cash flow and other factors. Our board of directors intends to continue the payment of dividends to the holders of the Company's common stock in the future; however, the Company can provide no assurance that dividends will be authorized or declared in the future or as to the amount or type of any future dividends. Our board of directors' determination with respect to any such dividends, whether base or variable, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination.

Recent Sales of Unregistered Securities

None.

Issuer Repurchases of Equity Securities

Our common stock repurchase activity for the three months ended December 31, 2022 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid Per Share(1)	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)
	($ In millions, except per share amounts, shares in thousands)			
October 1, 2022 - October 31, 2022	53	$ 130.39	43	$ 2,782
November 1, 2022 - November 30, 2022	—	$ —	—	$ 2,782
December 1, 2022 - December 31, 2022	2,302	$ 134.58	2,302	$ 2,472
Total	2,355	$ 134.49	2,345	

(1) The average price paid per share includes any commissions paid to repurchase stock.

(2) In September 2021, the Company's board of directors authorized a $2.0 billion common stock repurchase program. On July 28, 2022, our board of directors approved an increase in our common stock repurchase program from $2.0 billion to $4.0 billion. The stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time.

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 appearing elsewhere in this Annual 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. See Item 1A. "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. As of December 31, 2022, we have one reportable segment, the upstream segment. See Note 1—Description of the Business and Basis of Presentation and Note 17—Segment Information of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion.

2022 Financial and Operating Highlights

- We recorded net income of $4.4 billion for the year ended December 31, 2022.
- Increased our annual base dividend by 50% to $3.00 per share and paid dividends to stockholders of $1.6 billion during 2022 and in February 2023 declared a combined base and variable cash dividend of $2.95 per share of common stock, payable in the first quarter of 2023. Additionally on February 16, 2023, our board of directors approved an increase to the Company's annual base dividend to $3.20 per share.
- Repurchased $1.1 billion of our common stock, leaving approximately $2.5 billion available for future purchases under our common stock repurchase program at December 31, 2022.
- During the year ended December 31, 2022, we issued $2.5 billion in principal amount of senior notes and retired an aggregate of $2.4 billion in principal amount of our then-outstanding senior notes.
- Our average production was 386,005 MBOE/d during the year ended December 31, 2022.
- During the year ended December 31, 2022, we drilled 240 gross horizontal wells (including 197 in the Midland Basin and 43 in the Delaware Basin).
- We turned 255 gross operated horizontal wells (including 213 in the Midland Basin and 42 in the Delaware Basin) to production and had capital expenditures, excluding acquisitions, of $1.9 billion during the year ended December 31, 2022.
- As of December 31, 2022, we had approximately 508,767 net acres, which primarily consisted of 325,540 net acres in the Midland Basin and 150,719 net acres in the Delaware Basin. As of December 31, 2022, we had an estimated 8,276 gross horizontal locations that we believe to be economic at $50.00 per Bbl WTI. In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 775,180 gross acres and 26,315 net royalty acres in the Permian Basin. We operate approximately 57% of these net royalty acres.

2022 Transactions and Recent Developments

Pending Divestiture Transactions

In February 2023, we entered into definitive agreements with unrelated third-party buyers to divest non-core assets consisting of approximately 19,000 net acres in Glasscock County and approximately 4,900 net acres in Ward and Winkler counties for combined total consideration of $439 million, subject to certain closing adjustments. The assets being sold in these pending transactions include approximately 2 MBO/d (7 MBOE/d) of 2023 production. Both of these transactions are expected to close in the second quarter of 2023, subject to completion of diligence and satisfaction of customary closing conditions.

Lario Acquisition

On January 31, 2023, we closed on the Lario Acquisition, which included approximately 25,000 gross (15,000 net) acres in the Midland Basin and certain related oil and gas assets in exchange for 4.33 million shares of our common stock and $814 million, including certain customary closing adjustments.

Gray Oak Divestiture

On January 9, 2023, we divested our 10% non-operating equity investment in Gray Oak for $172 million in cash proceeds and recorded a gain on the sale of equity method investments of approximately $53 million in the first quarter of 2023.

2022 Acquisition Activity

On January 18, 2022, we acquired, from an unrelated third-party seller, approximately 6,200 net acres in the Delaware Basin for $232 million in cash, including customary closing adjustments.

On August 24, 2022, we completed the merger with Rattler pursuant to which we acquired all of the approximately 38.51 million publicly held outstanding common units of Rattler in exchange for approximately 4.35 million shares of our common stock.

On November 30, 2022, we acquired all leasehold interests and related assets of FireBird Energy LLC, which included approximately 75,000 gross (68,000 net) acres in the Midland Basin and certain related oil and gas assets, in exchange for 5.92 million shares of our common stock and $787 million of cash, including certain customary closing adjustments.

Additionally during the year ended December 31, 2022, we acquired, from unrelated third-party sellers, approximately 4,000 net acres in the Permian Basin for an aggregate purchase price of approximately $220 million in cash, including customary closing adjustments.

2022 Divestiture Activity

In October 2022, we completed the divestiture of non-core Delaware Basin acreage consisting of approximately 3,272 net acres, with net production of approximately 550 BO/d (800 BOE/d) for $155 million of net proceeds. We used the net proceeds from this transaction towards debt reduction.

See Note 4—Acquisitions and Divestitures and Note 16—Subsequent Events of the notes to the consolidated financial statements included elsewhere in this Annual Report for additional discussion of these transactions.

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, including any economic downturn or recession that has occurred or may occur in the future, 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. During 2022, 2021 and 2020 the NYMEX WTI price for crude oil ranged from $(37.63) to $123.70 per Bbl, and the NYMEX Henry Hub price of natural gas ranged from $1.48 to $9.68 per MMBtu, with seven-year highs reached in 2022. The war in Ukraine, the COVID-19 pandemic, rising interest rates, global supply chain disruptions, concerns about a potential economic downturn or recession and recent measures to combat persistent inflation contributed to economic and pricing volatility during 2022 and may continue to impact prices in 2023. Although the impact of inflation on our business has been insignificant in prior periods, inflation in the U.S. has been rising at its fastest rate in over 40 years, creating inflationary pressure on the cost of services, equipment and other goods in the energy industry and other sectors, which is contributing to labor and materials shortages across the supply-chain. Additionally, OPEC and its non-OPEC allies, known collectively as OPEC+, continues to meet regularly to evaluate the state of global oil supply, demand and inventory levels. However, pricing may remain volatile during of 2023.

Outlook

After giving effect for the recently completed the FireBird and Lario acquisitions, we expect to hold our pro forma oil production levels essentially flat in 2023. During 2022, we had total capital expenditures of $1.9 billion, which was consistent with our guidance presented in November of 2022. During the second quarter of 2022, we announced an increase to our quarterly return of capital commitment to at least 75% of our free cash flow beginning in the third quarter of 2022.

Accordingly, we are utilizing our free cash flow to meet our quarterly return of capital commitment and for debt repayment rather than expanding our drilling program. During 2022, we continued to pay down debt and believe we have a strong balance sheet that can withstand another down cycle. We are focused on maintaining high cash margins and a low-cost structure to drive an increasing return on capital and operational excellence, and to mitigate inflationary pressures through improvements and efficiencies in our drilling and completion programs. Going forward, we intend to continue to remain flexible and use a combination of our growing and sustainable base dividend, variable dividend and opportunistic share repurchase program to generate the highest value proposition for our stockholders.

In the Midland Basin, we continued to have positive results across our core development areas located within Midland, Martin, Howard, Glasscock and Andrews counties, where development has primarily focused on drilling long-lateral, multi-well pads targeting the Spraberry and Wolfcamp formations.

In the Delaware Basin, we continued to target the Wolfcamp and Bone Spring formations across our primary development areas located in Pecos, Reeves and Ward counties. Collectively, the Delaware Basin accounted for approximately 15% of our total development in 2022, and we expect a similar portion of our total development to be focused in these areas in 2023.

As of December 31, 2022, we were operating 19 drilling rigs and four completion crews and currently intend to operate between 13 and 19 drilling rigs and between four and seven completion crews in 2023 on average across our current acreage position in the Midland and Delaware Basins.

Additionally, in the first quarter of 2023, we announced a target to sell at least $1.0 billion of non-core assets by year-end 2023, up from the previously announced target of $500 million.

Environmental Responsibility Initiatives and Highlights

In September 2022, we announced our medium-term goal to reduce Scope 1 and Scope 2 GHG intensity reduction by at least 50% from our 2020 level by 2030 and a short-term goal to implement continuous emission monitoring systems (“CEMS”) on our facilities to cover at least 90% of operated oil production by the end of 2023. As of December 31, 2022, we had installed CEMS that cover approximately 85% of our operated oil production.

In September 2021, we announced our near-term goal to end routine flaring (as defined by the World Bank) by 2025 and a near-term target to source over 65% of our water used for drilling and completion operations from recycled sources by 2025. For the full year ended 2022, we flared approximately 2.3% of our gross natural gas production and sourced approximately 41% of our water used for drilling and completion operations from recycled sources.

In February 2021, we announced significant enhancements to our commitment to environmental, social responsibility and governance, or ESG, performance and disclosure, including Scope 1 and methane emission intensity reduction targets. Our goals include the reduction of our Scope 1 greenhouse gas intensity by at least 50% and methane intensity by at least 70%, in each case by 2024 from the 2019 levels. To further underscore our commitment to carbon neutrality, we have also implemented our “Net Zero Now” initiative under which, effective January 1, 2021, we strive to produce every hydrocarbon molecule with zero net Scope 1 emissions. To the extent our greenhouse gas and methane intensity targets do not eliminate our carbon footprint, we have purchased carbon credits to offset the remaining emissions. We have also increased the weighting of ESG metrics from 20% to 25% in our annual short-term incentive compensation plan to motivate our executives and our employees to advance our environmental responsibility goals.

2023 Capital Budget

We have currently budgeted 2023 total capital spend of $2.50 billion to $2.70 billion. Should commodity prices weaken, we intend to act responsibly and, consistent with our prior practices, reduce capital spending. If commodity prices strengthen, we intend to maintain flat oil production, pay down indebtedness and return cash to our stockholders.

Results of Operations

The following discussion focuses primarily on a comparison of the results of operations between the years ended December 31, 2022 and 2021. For a discussion of the results of operations for the year ended December 31, 2021 as compared to the year ended December 31, 2020, 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, 2021 (filed with the SEC on February 24, 2022), which is incorporated in this report by reference from such prior report on Form 10-K.

The following table sets forth selected historical operating data for the periods indicated:

	Year Ended December 31,	
	2022	2021
Revenues (in millions):		
Oil sales	$ 7,660	$ 5,396
Natural gas sales	858	569
Natural gas liquid sales	1,048	782
Total oil, natural gas and natural gas liquid revenues	$ 9,566	$ 6,747
Production Data:		
Oil (MBbls)	81,616	81,522
Natural gas (MMcf)	176,376	169,406
Natural gas liquids (MBbls)	29,880	27,246
Combined volumes (MBOE)(1)	140,892	137,002
Daily oil volumes (BO/d)	223,605	223,348
Daily combined volumes (BOE/d)(1)	386,005	375,349
Average Prices:		
Oil ($ per Bbl)	$ 93.85	$ 66.19
Natural gas ($ per Mcf)	$ 4.86	$ 3.36
Natural gas liquids ($ per Bbl)	$ 35.07	$ 28.70
Combined ($ per BOE)	$ 67.90	$ 49.25
Oil, hedged ($ per Bbl)(2)	$ 86.76	$ 52.56
Natural gas, hedged ($ per Mcf)(2)	$ 4.12	$ 2.39
Natural gas liquids, hedged ($ per Bbl)(2)	$ 35.07	$ 28.33
Average price, hedged ($ per BOE)(2)	$ 62.85	$ 39.87

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per Bbl.
(2) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices and include gains and losses on cash settlements for matured commodity derivatives, which we do not designate for hedge accounting. Hedged prices exclude gains or losses resulting from the early settlement of commodity derivative contracts.

Production Data

Substantially all of our revenues are generated through the sale of oil, natural gas and natural gas liquids production. The following table provides information on the mix of our production for the years ended December 31, 2022 and 2021:

	Year Ended December 31,	
	2022	2021
Oil (MBbls)	58 %	60 %
Natural gas (MMcf)	21 %	20 %
Natural gas liquids (MBbls)	21 %	20 %
	100 %	100 %

See "Items 1 and 2. Business and Properties— Oil and Natural Gas Production Prices and Production Costs" for further discussion of production by basin.

Comparison of the Years Ended December 31, 2022 and 2021

Oil, Natural Gas and Natural Gas Liquids Revenues. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes.
Our oil, natural gas and natural gas liquids revenues increased by approximately $2.8 billion, or 42%, to $9.6 billion for the year ended December 31, 2022 from $6.7 billion for the year ended December 31, 2021. Higher average oil prices, and to a lesser extent natural gas and natural gas liquids prices, contributed $2.7 billion of the total increase. The remainder of the overall change is due to a 3% increase in combined volumes sold.

Higher commodity prices during 2022 compared to 2021 primarily reflect the increase in demand for oil due to economic recovery from the COVID-19 pandemic and other macroeconomic factors such as the war in Ukraine as discussed in "—*Commodity Prices and Certain Other Market Considerations*" above. The increase in production for the year ended December 31, 2022 compared to the same period in 2021 resulted primarily from recognizing a full year of production in the current period associated with production from the Guidon Acquisition and the QEP Merger, which occurred late in the first quarter 2021, and new well additions between periods.

Lease Operating Expenses. The following table shows lease operating expenses for the years ended December 31, 2022 and 2021:

	Year Ended December 31,			
	2022		2021	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Lease operating expenses	$ 652	$ 4.63	$ 565	$ 4.12

Lease operating expenses for the year ended December 31, 2022 as compared to the year ended December 31, 2021 increased by $87 million, or $0.51 per BOE, primarily due to an overall increase in utility and service costs driven by continued inflation. As a result of inflationary pressures, we expect our total lease operating expenses in 2023 to range from approximately $785 million to $883 million.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the years ended December 31, 2022 and 2021:

	Year Ended December 31,			
	2022		2021	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Production taxes	$ 483	$ 3.43	$ 349	$ 2.55
Ad valorem taxes	128	0.91	76	0.55
Total production and ad valorem expense	$ 611	$ 4.34	$ 425	$ 3.10
Production taxes as a % of oil, natural gas, and natural gas liquids revenue	5.0 %		5.2 %	

In general, production taxes are directly related to production revenues and are based upon current year commodity prices. Production taxes as a percentage of production revenues remained consistent for the year ended December 31, 2022 compared to the same period in 2021.

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, 2022 compared to the year ended December 31, 2021 increased by $52 million primarily due to higher overall valuations resulting from an increase in commodity prices between valuation periods.

We expect production and ad valorem taxes to be approximately 7% to 8% of oil, natural gas and natural gas liquids revenue during 2023.

Gathering and Transportation Expense. The following table shows gathering and transportation expense for the years ended December 31, 2022 and 2021:

	Year Ended December 31,			
	2022		2021	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Gathering and transportation	$ 258	$ 1.83	$ 212	$ 1.55

The increase in gathering and transportation expenses for the year ended December 31, 2022 compared to the same period in 2021 is primarily due to the increase in production between periods as well as an overall increase in the cost per BOE. The increase in cost is largely attributable to higher third-party gas gathering expenses of approximately $30 million related to gathering fees incurred after we divested certain gas gathering assets during the fourth quarter of 2021, and minimum volume commitment fees of approximately $8 million. The remaining increase primarily related to rate escalations on our gathering and transportation contracts.

We expect gathering and transportation expenses to range from approximately $283 million to $321 million in 2023.

Depreciation, Depletion, Amortization and Accretion. The following table provides the components of our depreciation, depletion and amortization expense for the years ended December 31, 2022 and 2021:

	Year Ended December 31,	
(In millions, except BOE amounts)	**2022**	**2021**
Depletion of proved oil and natural gas properties	$ 1,250	$ 1,202
Depreciation of other property and equipment	77	48
Other amortization	3	16
Asset retirement obligation accretion	14	9
Depreciation, depletion, amortization and accretion expense	$ 1,344	$ 1,275
Oil and natural gas properties depletion rate per BOE	$ 8.87	$ 8.77

The increase in depletion of proved oil and natural gas properties of $48 million for the year ended December 31, 2022 as compared to the year ended December 31, 2021 resulted largely from higher production volumes and a slight increase in the average depletion rate.

Impairment of Oil and Natural Gas Properties. No impairment expense was recorded for the year ended December 31, 2022. In connection with the QEP Merger and the Guidon Acquisition, we recorded the oil and natural gas properties acquired at fair value. Pursuant to SEC guidance, we determined the fair value of the properties acquired in the QEP Merger and the Guidon Acquisition clearly exceeded the related full cost ceiling limitation beyond a reasonable doubt. As such, we requested and received a waiver from the SEC to exclude the acquired properties from the first quarter 2021 ceiling test calculation. As a result, no impairment expense related to the QEP Merger and the Guidon Acquisition was recorded for the three months ended March 31, 2021. Had we not received the waiver from the SEC, an impairment charge of approximately $1.1 billion would have been recorded in the first quarter of 2021. The properties acquired in the QEP Merger and the Guidon Acquisition had total unamortized costs at March 31, 2021 of $3.0 billion and $1.1 billion, respectively.

Impairment charges affect our results of operations but do not reduce our cash flow. See Note 5—Property and Equipment of the notes to the consolidated financial statements included elsewhere in this Annual Report and "*— Critical Accounting Estimates*" for further details regarding factors that impact the impairment of oil and natural gas properties.

General and Administrative Expenses. The following table shows general and administrative expenses for the years ended December 31, 2022 and 2021:

	Year Ended December 31,			
	2022		2021	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
General and administrative expenses	$ 89	$ 0.63	$ 95	$ 0.69
Non-cash stock-based compensation	55	0.39	51	0.37
Total general and administrative expenses	$ 144	$ 1.02	$ 146	$ 1.06

Total general and administrative expenses for the year ended December 31, 2022 were consistent with the same period in 2021 and there were no significant individual contributing factors to the change between periods.

We expect cash general and administrative expenses to range from approximately $102 million to $128 million in 2023, and non-cash stock-based compensation to range from approximately $63 million to $80 million in 2023.

Merger and Integration Expense. The following table shows merger and integration expense for the years ended December 31, 2022 and 2021:

	Year Ended December 31,			
	2022		2021	
(In millions)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Merger and integration expenses	$ 14	$ 0.10	$ 78	$ 0.57

Total merger and integration expense for the year ended December 31, 2022 relates to banking, legal and advisory fees of $11 million for the Rattler Merger, $2 million for the FireBird Acquisition, and $1 million for the Lario Acquisition.

Merger and integration expense for the year ended December 31, 2021 includes $69 million in costs incurred for the QEP Merger and $9 million in costs incurred for the Guidon Acquisition. The QEP Merger related expenses primarily consist of $39 million in severance costs and $30 million in banking, legal and advisory fees, and the Guidon Acquisition related expenses consist primarily of advisory and legal fees. See Note 4—Acquisitions and Divestitures of the notes to the consolidated financial statements included elsewhere in this Annual Report for further details regarding the QEP Merger and the Guidon Acquisition.

Derivative Instruments. The following table shows the net gain (loss) on derivative instruments and the net cash received (paid) on settlements of derivative instruments for the years ended December 31, 2022 and 2021:

	Year Ended December 31,	
(In millions)	**2022**	**2021**
Gain (loss) on derivative instruments, net(1)	$ (586)	$ (848)
Net cash received (paid) on settlements(2)(3)	$ (850)	$ (1,225)

(1) The year ended December 31, 2022 includes $57 million in losses related to interest rate swaps.
(2) The year ended December 31, 2022 includes cash paid on commodity contracts terminated prior to their contractual maturity of $138 million.
(3) The year ended December 31, 2021 includes cash paid on commodity contracts terminated prior to their contractual maturity of $16 million and cash received on interest rate swap contracts terminated prior to their contractual maturity of $80 million.

At December 31, 2022, we have a short-term derivative asset of $132 million, a long-term derivative asset of $23 million, a short-term derivative liability due in 2023 of $47 million and a long-term derivative liability due in 2024 of $148 million.

See Note 12—Derivatives of the notes to the consolidated financial statements included elsewhere in this Annual report for further details regarding our derivative instruments and interest rate swaps.

Other Income (Expense). The following table shows other income and expenses for the year ended December 31, 2022 and 2021:

(In millions)	Year Ended December 31, 2022	2021
Interest expense, net	$ (159)	$ (199)
Other income (expense), net	$ (5)	$ (10)
Gain (loss) on sale of equity method investments	$ —	$ 23
Gain (loss) on extinguishment of debt	$ (99)	$ (75)
Income (loss) from equity investments	$ 77	$ 15

The decrease in net interest expense for the year ended December 31, 2022 compared to the same period in 2021, primarily reflects a $36 million increase in capitalized interest costs, which reduce interest expense, and a $26 million decrease in interest expense on our senior notes due largely to redemptions and repurchases of principal between the periods. These reductions were partially offset by an $18 million increase in interest expense on our revolving credit facility. We expect interest expense to range from approximately $204 million to $225 million in 2023.

Gain (loss) on extinguishment of debt reflects the difference between the carrying value and reacquisition price for the repurchases and redemptions of various senior notes during the 2022 and 2021 periods.

See Note 8—Debt of the notes to the consolidated financial statements included elsewhere in this Annual report for further details outstanding borrowings, interest expense and gain (loss) on extinguishment of debt.

The increase in income from our equity investments primarily reflects higher capacity utilization and price realizations for our midstream investees in 2022 compared to 2021, as well as increase of $38 million in income from our investment in an interconnected gas gathering system in the Midland Basin, which was acquired in the fourth quarter of 2021.

Provision for (Benefit from) Income Taxes. The following table shows the provision for (benefit from) income taxes for the years ended December 31, 2022 and 2021:

(In millions)	Year Ended December 31, 2022	2021
Provision for (benefit from) income taxes	$ 1,174	$ 631

The change in our income tax provision for the year ended December 31, 2022 compared to the same period in 2021 was primarily due to the increase in pre-tax income which resulted largely from the changes in revenues from oil, natural gas and natural gas liquids. See Note 11—Income Taxes of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of our income tax expense.

Liquidity and Capital Resources

Overview of Sources and Uses of Cash

Historically, our primary sources of liquidity include cash flows from operations, proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of senior notes and sales of non-core assets. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties, payments to retire debt and interest expense on debt, dividends and share repurchases, and income taxes, At December 31, 2022, we had approximately $1.8 billion of liquidity consisting of $157.0 million in cash and cash equivalents and $1.6 billion available under our credit facility. As discussed below, our capital budget for 2023 is $2.50 billion to $2.70 billion.

Future cash flows are subject to a number of variables, including the level of oil and natural gas production, volatility of commodity prices, and significant additional capital expenditures will be required to more fully develop our properties. Prices for our commodities are determined primarily by prevailing market conditions, regional and worldwide economic activity, weather and other substantially variable factors. These factors are beyond our control and are difficult to predict. See Item 1A. “Risk Factors” above. In order to mitigate this volatility, we enter into derivative contracts with a number of financial institutions, all of which are participants in our credit facility, to economically hedge a portion of our estimated future crude oil and natural gas production through the end of 2023 as discussed further in Note 12—Derivatives of the notes to the consolidated financial statements included elsewhere in this Annual Report and Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk*. The level of our hedging activity and duration of the financial instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

Cash Flow

Our cash flows for the years ended December 31, 2022 and 2021 are presented below:

	Year Ended December 31,	
	2022	2021
	(In millions)	
Net cash provided by (used in) operating activities	$ 6,325	$ 3,944
Net cash provided by (used in) investing activities	(3,330)	(1,539)
Net cash provided by (used in) financing activities	(3,503)	(1,841)
Net change in cash	$ (508)	$ 564

Operating Activities

The increase in operating cash flows for the year ended December 31, 2022 compared to the same period in 2021 primarily resulted from (i) an increase of $2.8 billion in our total revenue, (ii) a decrease of $397 million in net cash paid on settlements of derivative contracts, and (iii) fluctuations in other working capital balances due primarily to the timing of when collections are made on accounts receivable and payments are made on accounts payable and accrued liabilities. These net cash inflows were partially offset by (i) a change of $856 million in cash paid for taxes due to making payments of $718 million in 2022 compared to receiving net refunds of $138 million in federal taxes under the 2020 CARES act in 2021, and (ii) an increase in our cash operating expenses of approximately $266 million. See "*—Results of Operations*" for discussion of significant changes in our revenues and expenses.

Investing Activities

Net cash used in investing activities was $3.3 billion compared to $1.5 billion for the years ended December 31, 2022 and 2021, respectively. The majority of our net cash used for investing activities during the year ended December 31, 2022 was for the purchase and development of oil and natural gas properties and related assets, including the FireBird Acquisition. These expenditures were partially offset by proceeds from the sale of certain non-core Delaware Basin assets and other assets discussed in Note 4—Acquisitions and Divestitures.

The majority of our net cash used in investing activities during the year ended December 31, 2021 was for the purchase and development of oil and natural gas properties and related assets, including the acquisition of certain leasehold interests as part of the Guidon Acquisition. These expenditures were partially offset by proceeds from the divestiture of our Williston Basin assets, leasehold acreage and other gathering assets discussed in Note 4—Acquisitions and Divestitures. Our capital expenditures for each period are discussed further below.

Capital Expenditure Activities

Our capital expenditures excluding acquisitions and equity method investments (on a cash basis) were as follows for the specified period:

	Year Ended December 31,	
	2022	2021
	(In millions)	
Drilling, completions and non-operated additions to oil and natural gas properties	$ 1,685	$ 1,334
Infrastructure additions to oil and natural gas properties	169	123
Additions to midstream assets	84	30
Total	$ 1,938	$ 1,487

For further discussion regarding our development program, please see the section entitled "Item 1 and 2. Business and Properties—*Wells Drilled and Completed in 2022*."

Financing Activities

Net cash used in financing activities for the year ended December 31, 2022 was $3.5 billion compared to net cash used in financing activities for the year ended December 31, 2021 of $1.8 billion. During the year ended December 31, 2022, the amount used in financing activities was primarily attributable to (i) $2.4 billion paid for the retirement of outstanding principal on certain senior notes, as well as $63 million of additional premiums paid in connection with the repurchases, (ii) $1.3 billion of repurchases as part of the share and unit repurchase programs, (iii) $1.6 billion of dividends paid to stockholders, and (iv) $217 million in distributions to non-controlling interest. The cash outflows were partially offset by (i) $2.5 billion in proceeds from our senior notes issued in 2022, and (ii) $347 million of borrowings under our and our subsidiaries' credit facilities, net of repayments.

Net cash used in financing activities for the year ended December 31, 2021 was primarily attributable to (i) $3.2 billion paid for the retirement of outstanding principal on certain senior notes, as well as $178 million of additional premiums paid in connection with the repurchases, (ii) $525 million of repurchases as part of the share and unit repurchase programs, (iii) $312 million of dividends paid to stockholders, and (iv) $112 million in distributions to non-controlling interest. The cash outflows were partially offset by (i) $2.2 billion in proceeds our senior notes issued in 2021, (ii) $313 million of borrowings under our and our subsidiaries' credit facilities, net of repayments and (iii) $22 million in net cash receipts from the early settlement of interest rate swaps and commodity derivative contracts that contained an other-than-insignificant financing element.

Capital Resources

Our working capital requirements are supported by our cash and cash equivalents and available borrowings under our revolving credit facility. We may draw on our 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, 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 capital requirements.

As we pursue our business and financial strategy, we regularly consider which capital resources, including cash flow and equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. Continued prolonged volatility in the capital, financial and/or credit markets due to the war in Ukraine, the COVID-19 pandemic and/or adverse macroeconomic conditions may limit our access to, or increase our cost of, capital or make capital unavailable on terms acceptable to us or at all.

Revolving Credit Facilities and Senior Notes

As of December 31, 2022, the maximum credit amount available under our credit agreement was $1.6 billion, which may be increased in an amount up to $1.0 billion (for a total maximum commitment amount of $2.6 billion), with no outstanding borrowings and an aggregate of $3 million in outstanding letters of credit which reduce available borrowings on a dollar for dollar basis. During the second quarter of 2022, we extended the maturity date on our credit agreement by one year to June 2, 2027, and may further extend it by two one-year extensions pursuant to the terms set forth in the credit agreement.

During the year ended December 31, 2022, we issued $2.5 billion in principal amount of senior notes with extended maturity dates ranging from 2033 through 2053.

See Note 8—Debt of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of our revolving credit facility and senior notes.

Viper's Revolving Credit Facility

Viper's credit agreement, as amended to date, matures on June 2, 2025 and provides for a revolving credit facility in the maximum credit amount of $2.0 billion, with a borrowing base of $580 million as of December 31, 2022, although Viper had an elected commitment amount of $500 million, based on Viper LLC's oil and natural gas reserves and other factors. At December 31, 2022, there were $152 million of outstanding borrowings and $348 million available for future borrowings under Viper's credit agreement.

Capital Requirements

In addition to future operating expenses and working capital commitments discussed in "*—Results of Operations*", our primary short and long-term liquidity requirements consist primarily of (i) capital expenditures, (ii) payments of principal and interest on our revolving credit agreements and senior notes, (ii) payments of other contractual obligations, (iii) cash commitments for dividends and share repurchases, and (iv) income taxes.

2023 Capital Spending Plan

Our board of directors approved a 2023 capital budget for drilling, midstream and infrastructure of $2.50 billion to $2.70 billion. We estimate that, of these expenditures, approximately:

- $2.25 billion to $2.41 billion will be spent primarily on drilling 325 to 345 gross (293 to 311 net) horizontal wells and completing 330 to 350 gross (297 to 315 net) horizontal wells across our operated and non-operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 10,500 feet;
- $80 million to $100 million will be spent on midstream infrastructure, excluding joint venture investments; and
- $170 million to $190 million will be spent on infrastructure and environmental expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The amount and timing of our capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence and our capital expenditure budget up or down in response to changes in commodity prices and overall market conditions.

Payments of Principal and Interest on Senior Notes

During the year ended December 31, 2022 we retired $2.4 billion in principal amount of our then-outstanding senior notes with a portion of the net proceeds from our senior notes offerings completed in March and October of 2022, cash on hand and borrowings under Viper's revolving credit facilities, as applicable, as discussed further in Note 8—Debt of the notes to the consolidated financial statements included elsewhere in this Annual Report.

At December 31, 2022, we have total principal payments due on our outstanding senior notes, including those of Viper, of $10 million in 2023, $1.2 billion cumulatively in the years 2026 and 2027, and $5.0 billion thereafter. Additionally, we expect to incur future cash interest costs on these senior notes of approximately $265 million in 2023, $530 million cumulatively in the years from 2024 through 2025, $504 million cumulatively in the years from 2026 and 2027, and $2.9 billion cumulatively between 2028 and 2053.

Other Contractual Obligations and Commitments

At December 31, 2022, our other significant contractual obligations consist primarily of (i) minimum transportation commitments totaling $856 million, (ii) asset retirement obligations totaling $347 million, (iii) electronic fracturing fleet and related power generation services commitments totaling $140 million and (iv) minimum purchase commitments for quantities of sand used in our drilling operations totaling $91 million. We expect to make aggregate payments of approximately $166 million for these commitments during 2023. See Note 6—Asset Retirement Obligations and Note 15—Commitments and Contingencies of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of these and other contractual obligations and commitments.

Dividends and Share Repurchases

In addition to our base dividend program, in the first quarter of 2022 we initiated a variable dividend strategy whereby we may pay a quarterly variable dividend based on the prior quarter's free cash flow remaining after the payment of the base dividend. Beginning in the third quarter of 2022, our board of directors approved an increase to this return of capital commitment to at least 75% of free cash flow. On February 16, 2023, our board of directors approved an increase to the

Company's annual base dividend to $3.20 per share. We have declared a base plus variable cash dividend for the fourth quarter of 2022 of $2.95 per share of common stock.

Free cash flow is a non-GAAP financial measure. As used by us, free cash flow is defined as cash flow from operating activities before changes in working capital in excess of cash capital expenditures. We believe that free cash flow is useful to investors as it provides a measure to compare both cash flow from operating activities and additions to oil and natural gas properties across periods on a consistent basis.

Future base and variable dividends are at the discretion of our board of directors, and the board of directors may change the dividend amount from time to time based on our outlook for commodity prices, liquidity, debt levels, capital resources, free cash flow and other factors. We can provide no assurance that dividends will be authorized or declared in the future or as to the amount and type of any future dividends. Any future variable dividends, whether base or variable, if declared and paid, will by their nature fluctuate based on our free cash flow, which will depend on a number of factors beyond the our control, including commodity prices.

As of February 17, 2023, we have repurchased 13.2 million shares of our common stock for a total cost of $1.6 billion since the inception of the repurchase program. We intend to continue to opportunistically purchase shares under this repurchase program with available funds primarily from cash flow from operations and liquidity events such as the sale of assets while maintaining sufficient liquidity to fund our capital expenditure programs. See Note 9—Stockholders' Equity and Earnings Per Share of the notes to the consolidated financial statements included elsewhere in this report for further discussion of the repurchase program.

Income Taxes

We expect our cash tax rate to be 10% to 15% of pre-tax income for the year ended December 31, 2023. See Note 11—Income Taxes of the notes to the consolidated financial statements included elsewhere in this Annual report for further discussion of our income taxes.

Debt Ratings

We receive debt ratings from the major ratings agencies in the U.S. In determining our debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, our liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales and production growth opportunities. Our credit ratings from the three main credit rating agencies are as follows:

- Standard and Poor's Global Ratings Services (BBB-);
- Fitch Investor Services (BBB); and
- Moody's Investor Services (Baa2).

Any rating downgrades may result in additional letters of credit or cash collateral being posted under certain contractual arrangements.

Guarantor Financial Information

Diamondback E&P is the sole guarantor under the indentures governing the outstanding Guaranteed Senior Notes.

Guarantees are "full and unconditional," as that term is used in Regulation S-X, Rule 3-10(b)(3), except that such guarantees will be released or terminated in certain circumstances set forth in the indentures governing the Guaranteed Senior Notes, such as, with certain exceptions, (i) in the event Diamondback E&P (or all or substantially all of its assets) is sold or disposed of, (ii) in the event Diamondback E&P ceases to be a guarantor of or otherwise be an obligor under certain other indebtedness, and (iii) in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the relevant indenture.

Diamondback E&P's guarantees of the Guaranteed Senior Notes are senior unsecured obligations and rank senior in right of payment to any of its future subordinated indebtedness, equal in right of payment with all of its existing and future senior indebtedness, including its obligations under its revolving credit facility, and effectively subordinated to any of its existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The rights of holders of the Guaranteed Senior Notes against Diamondback E&P may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Each guarantee contains a provision intended to limit Diamondback E&P's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent conveyance. However, there can be no assurance as to what standard a court will apply in making a determination of the maximum liability of Diamondback E&P. Moreover, this provision may not be effective to protect the guarantee from being voided under fraudulent conveyance laws. There is a possibility that the entire guarantee may be set aside, in which case the entire liability may be extinguished.

The following tables present summarized financial information for Diamondback Energy, Inc., as the parent, and Diamondback E&P, as the guarantor subsidiary, on a combined basis after elimination of (i) intercompany transactions and balances between the parent and the guarantor subsidiary and (ii) equity in earnings from and investments in any subsidiary that is a non-guarantor. The information is presented in accordance with the requirements of Rule 13-01 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiary operated as an independent entity.

Summarized Balance Sheets:	December 31, 2022 (In millions)
Assets:	
Current assets	$ 1,191
Property and equipment, net	$ 18,252
Other noncurrent assets	$ 164
Liabilities:	
Current liabilities	$ 1,547
Intercompany accounts payable, non-guarantor subsidiary	$ 2,253
Long-term debt	$ 5,647
Other noncurrent liabilities	$ 2,509

Summarized Statement of Operations:	Year Ended December 31, 2022 (In millions)
Revenues	$ 7,630
Income (loss) from operations	$ 5,023
Net income (loss)	$ 3,095

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 accounting principles generally accepted in the United States.

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 and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates and assumptions on a regular basis. Critical accounting estimates are those estimates made in accordance with generally accepted accounting principles that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on the financial condition or results of operations of the registrant. 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.

Oil and Natural Gas Accounting and Reserves

We account for our 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 proved oil and natural gas properties including 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 Company, L.P., independent petroleum engineers, as of December 31, 2022 and prepared by Ryder Scott as of December 31, 2021 and 2020. 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 our estimate of operating and development costs, 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 reported reserve estimates 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. Revisions of previous reserve estimates accounted for approximately $102 million, or 1% of the change in the standardized measure of our total reserves from December 31, 2021 to December 31, 2022. No impairments were recorded for our proved oil and gas properties during the years ended December 31, 2022 and 2021; however, a material impairment was recorded during the year ended December 31, 2020 as discussed further in Note 5—Property and Equipment of the notes to the consolidated financial statements included elsewhere in this Annual Report. Due to an increase in the historical 12-month average trailing SEC prices for oil and natural throughout 2021 and into 2022, we are not currently projecting a full cost ceiling impairment in the first quarter of 2023.

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: 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. At December 31, 2022, our unevaluated properties totaled $8.4 billion, which consisted of 236,253 net undeveloped leasehold acres with approximately 465 net acres set to expire in 2023. We did not record any impairment on our unevaluated properties during the year ended December 31, 2022, but any such future impairment could potentially be material to our consolidated financial statements.

Commodity Derivatives

From time to time, we use commodity derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil and natural gas. We exercise significant judgment in determining the types of instruments to be used, the level of production volumes to include in our commodity derivative contracts, the prices at which we enter into commodity derivative contracts and the counterparties' creditworthiness. We do not use these instruments for speculative or trading purposes.

We have not designated our derivative instruments as hedges for accounting purposes and, as a result, mark our derivative instruments to fair value and recognize the cash and non-cash change in fair value on derivative instruments for each period in the consolidated statements of operations. We are also required to recognize our 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, and is generally determined using various inputs and assumptions including established index prices and other sources which are based upon, among other things, futures prices, time to maturity, implied volatilities and counterparty credit risk.

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. Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur.

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk* for additional sensitivity analysis of our open derivative positions at December 31, 2022.

Business Combinations

We account for business combinations using the acquisition method of accounting. Accordingly, identifiable assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. Fair value estimates are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. When market-observable prices are not available to value assets and liabilities, the Company may use the cost, income, or market valuation approaches depending on the quality of information available to support management's assumptions.

The most significant assumptions relate to the estimated fair values assigned to our proved and unproved oil and natural gas properties. The assumptions made in performing these valuations include future production volumes, future commodity prices and costs, future operating and development activities, projections of oil and gas reserves and a weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of natural gas and oil properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Changes in key assumptions may cause the acquisition accounting to be revised, including the recognition of additional goodwill or discount on acquisition. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected. See Note 4—Acquisitions and Divestitures of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of the estimated fair value of assets acquired and liabilities assumed in the QEP Merger, Guidon Acquisition and FireBird Acquisition, including any significant changes in these estimates from the date of acquisition.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings.

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 (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) 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.

In 2022, management's assessment of all available evidence, both positive and negative, supporting realizability of Viper's deferred tax assets as required by applicable accounting standards, resulted in recognition of an income tax benefit of $50 million for the portion of Viper's deferred tax assets considered more likely than not to be realized. The positive evidence assessed included recent cumulative income due in part to higher commodity prices and an expectation of future taxable income based upon recent actual and forecasted production volumes and prices. Viper retained a partial valuation allowance on its deferred tax assets due in part to potential future volatility in commodity prices impacting the likelihood of future realizability. As of December 31, 2022, Viper had a deferred tax asset of $148 million offset by an allowance of $98 million. The valuation allowance remains in place based on the uncertainty of future events, including Viper's ability to generate future taxable income in excess of special allocations to be made to Diamondback, and management considered this and other factors in evaluating the realizability of Viper's deferred tax assets. Any changes in the positive or negative evidence evaluated when determining if Viper's deferred tax assets will be realized, including projected future income, could result in a material change to our consolidated financial statements. In addition, the determination to record a valuation allowance on certain tax attributes acquired from QEP and certain state NOL carryforwards which the Company does not believe are realizable prior to expiration was based on an evaluation of available positive and negative evidence, including the annual limitation imposed by IRC Section 382 subsequent to an ownership change and the anticipated timing of reversal of the Company's deferred tax liabilities in the applicable jurisdictions. As of December 31, 2022, our balance of taxable temporary differences anticipated to reverse within the carryforward period provides significant positive evidence for the determination that our remaining deferred tax assets are more likely than not to be realized. Any change in the positive or negative evidence evaluated when determining if our deferred tax assets will be realized, including projected future taxable income primarily related to the excess of book carrying value over tax basis of our oil and natural gas properties, could result in a material change to our consolidated financial statements.

The accruals for deferred tax assets and liabilities are often based on uncertain tax positions and 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. At December 31, 2022, our uncertain tax positions were insignificant, however, 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 of the notes to the consolidated financial statements included elsewhere in this Annual Report for recent accounting pronouncements not yet adopted, if any.

Off-Balance Sheet Arrangements

See Note 15—Commitments and Contingencies of the notes to the consolidated financial statements included elsewhere in this Annual Report for a discussion of our significant commitments and contingencies, some of which are not recognized in the consolidated balance sheets under GAAP.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure in our exploration and production business is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years. Although demand and market prices for oil and natural gas have recently increased, we cannot predict events, including the outcome of the war in Ukraine, rising interest rates, global supply chain disruptions, a potential economic downturn or recession, the COVID-19 pandemic, that may lead to future price volatility and the near term energy outlook remains subject to heightened levels of uncertainty. Further, the prices we receive for production depend on many other factors outside of our control.

We use derivatives, including swaps, basis swaps, swaptions, roll hedges, costless collars, puts and basis puts, to reduce price volatility associated with certain of our oil and natural gas sales.

At December 31, 2022, we had a net asset commodity derivative position of $153 million related to our commodity price derivatives. Utilizing actual derivative contractual volumes under our commodity price derivatives as of December 31, 2022, a 10% increase in forward curves associated with the underlying commodity would have increased the net asset position by $11 million to $164 million, while a 10% decrease in forward curves associated with the underlying commodity would have reduced the net asset derivative position by $8 million to $145 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

For additional information on our open commodity derivative instruments at December 31, 2022, see Note 12—Derivatives of the notes to the consolidated financial statements included elsewhere in this Annual Report.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are due to the concentration of receivables from the sale of our oil and natural gas production (approximately $618 million at December 31, 2022), and to a lesser extent, receivables resulting from joint interest receivables (approximately $93 million at December 31, 2022).

We do not require our customers to post collateral, and the failure or inability of our significant customers to meet their obligations to us due to their liquidity issues, bankruptcy, insolvency or liquidation may adversely affect our financial results.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facilities and changes in the fair value of our fixed rate debt. Outstanding borrowings under the credit agreement bear interest at a per annum rate elected by Diamondback E&P. At December 31, 2022, the applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternate base rate, and from 1.125% to 2.000% per annum in the case of Adjusted Term SOFR, in each case based on the pricing level. The pricing level depends on certain rating agencies' ratings of our long-term senior unsecure debt. We believe significant interest rate changes would not have a material near-term impact on our future earnings or cash flows. For additional information on our variable interest rate debt at December 31, 2022, see Note 8—Debt of the notes to the consolidated financial statements included elsewhere in this Annual Report.

Historically, we have at times used interest rates swaps to manage our exposure to (i) interest rate changes on our floating-rate date and (ii) fair value changes on our fixed rate debt. At December 31, 2022, we have interest rate swap agreements for a notional amount of $1.2 billion to manage the impact of changes to the fair value of our fixed rate senior notes due to changes in market interest rates through December 2029. We pay an average variable rate of interest for these swaps based on three month LIBOR plus 2.1865% and receive a fixed interest rate of 3.50% from our counterparties. At December 31, 2022, our receive-fixed, pay-variable interest rate swaps were in a net liability position of $193 million, and the weighted average variable rate was 5.97%. For additional information on our interest rate swaps, see Note 12—Derivatives of the notes to the consolidated financial statements included elsewhere in this Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control 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, 2022, 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, 2022, 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, 2022 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 the Company is responsible for establishing and maintaining adequate internal control over financial reporting. 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, 2022.

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, 2022. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2022, 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
Diamondback Energy, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2022, 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, 2022, 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, 2022, and our report dated February 23, 2023 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 23, 2023

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

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, 2022.

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 http://ir.diamondbackenergy.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, 2022.

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, 2022.

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, 2022.

ITEM 14. PRINCIPAL ACCOUNTING 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, 2022.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(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.

3. Exhibits

Exhibit Number	Description
2.1#	Agreement and Plan of Merger, dated as of December 20, 2020, by and among Diamondback Energy, Inc., Bohemia Merger Sub, Inc. and QEP Resources, Inc. (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 21, 2020).
2.2#	Agreement and Plan of Merger, dated as of May 15, 2022, by and among Diamondback Energy, Inc., Rattler Midstream GP LLC, Bacchus Merger Sub Company and Rattler Midstream LP (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by Diamondback Energy, Inc. with the SEC on May 16, 2022).
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Certificate of Amendment No. 1 of the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 12, 2016).
3.3	Certificate of Amendment No. 2 to the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 8, 2021).
3.4	Third Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 3, 2023).
4.1	Description of the Company’s Securities (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-8, File No. 333-257561, filed by the Company with the SEC on June 30, 2021).
4.2	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.3	Registration Rights Agreement, dated as of February 26, 2021, by and among the Company, Guidon Operating LLC and Guidon Energy Holdings LP (incorporated by reference to Exhibit 4.3 to the Company’s Registration Statement on Form S-3, File No. 333-255731, filed by the Company with the SEC on May 3, 2021.
4.4	Letter Agreement, dated as of April 27, 2021, by and among the Company, Guidon Operating LLC and Guidon Energy Holdings LP relating to the Registration Rights Agreement referenced as Exhibit 4.2 hereto (incorporated by reference to Exhibit 4.4 to the Company’s Registration Statement on Form S-3, File No. 333-255731, filed by the Company with the SEC on May 3, 2021.
4.5	Indenture, dated as of December 5, 2019, between Diamondback Energy, Inc. and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 5, 2019).
4.6	First Supplemental Indenture, dated as of December 5, 2019, among Diamondback Energy, Inc., Diamondback E&P LLC, as successor by merger to Diamondback O&G LLC, and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (including the forms of 3.250% Senior Notes due 2026 and 3.500% Senior Notes due 2029) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 5, 2019).

3. Exhibits

Exhibit Number	Description
4.7	Third Supplemental Indenture, dated as of March 24, 2021, among Diamondback Energy, Inc., Diamondback E&P LLC, as successor by merger to Diamondback O&G LLC, and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (including the forms of 3.125% Senior Notes due 2031 and 4.400% Senior Notes due 2051) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 24, 2021).
4.8	Fourth Supplemental Indenture, dated as of June 30, 2021, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as successor trustee to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 5, 2021).
4.9	Fifth Supplemental Indenture, dated as of March 17, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as trustee (including the form of 4.250% Senior Notes due 2052) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 17, 2022).
4.10	Sixth Supplemental Indenture, dated as of October 28, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association (including the form of 6.250% Senior Notes due 2033) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 28, 2022).
4.11	Indenture, dated as of October 16, 2019, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor, and Wells Fargo Bank, National Association, as trustee (including the form of Viper Energy Partners LP's 5.375% Senior Notes due 2027) (incorporated by reference to Exhibit 4.1 of Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.12	Consent Letter, dated August 28, 2019, between Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc. as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File 001-35700) filed on September 4, 2019).
4.13	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 Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.14	Form of Indenture, dated September 1, 1996, between Energen Corporation and The Bank of New York as trustee (incorporated by reference to Exhibit 4(i) to Energen Corporation's Registration Statement on Form S-3 (Registration No. 333-11239), filed with the SEC on August 30, 1996).
4.15	Amended and Restated Officers' Certificate, dated as of February 27, 1998, between Energen Corporation and The Bank of New York as trustee, relating to the Medium-Term Notes, Series B, due 2028 (incorporated by reference to Exhibit 4(a)(iii) to the Form 10-K, File No. 001-7810, filed by Energen Corporation with the SEC on February 28, 2018).
4.16	Indenture, dated as of March 1, 2012, between QEP Resources, Inc. and Wells Fargo Bank, National Association as trustee (incorporated by reference to Exhibit 4.1 to QEP Resources Inc.'s Current Report on Form 8-K, filed with the SEC on March 1, 2012).
4.17	Officer's Certificate, dated as of March 1, 2012 (including the form of the 5.375% Notes due 2022) (incorporated by reference to Exhibit 4.2 to QEP Resources, Inc.'s. Current Report on Form 8-K, filed with the SEC on March 1, 2012).
4.18	Officer's Certificate, dated as of September 12, 2012 (incorporated by reference to Exhibit 4.1 to QEP Resources, Inc.'s Current Report on Form 8-K, filed with the SEC on September 14, 2012).
4.19	Officer's Certificate, dated as of November 21, 2017 (including the form of the 5.625% Senior Notes due 2026) (incorporated by reference to Exhibit 4.2 to QEP Resources, Inc.'s Current Report on Form 8-K, filed with the SEC on November 21, 2017).
4.20	First Supplemental Indenture, dated as of March 23, 2021, among QEP Resources, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 24, 2021).
4.21	Indenture, dated as of December 13, 2022, between Diamondback Energy, Inc. and Computershare Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 13, 2022).
4.22	First Supplemental Indenture, dated as of December 13, 2022, among Diamondback Energy, Inc., Diamondback E&P LLC and Computershare Trust Company, National Association, as trustee (including the form of 6.250% Senior Notes due 2053) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 13, 2022).
10.1+	2020 Form of Time Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 of the Company's Annual Report on Form 10-K (File 001-35700) filed on February 27, 2020).
10.2+	2020 Form of Performance Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.3 of the Company's Annual Report on Form 10-K (File 001-35700) filed on February 27, 2020).
10.3+	2021 Amended and Restated Diamondback Energy, Inc. Equity Incentive Plan (incorporated by reference to Appendix B to Schedule DEF 14A filed by the Company with the SEC on April 23, 2021).

3. Exhibits

Exhibit Number	Description
10.4+	2021 Form of Time Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.4 of the Annual Report on Form 10-K (File 001-35700) filed by the Company with the SEC on February 25, 2021).
10.5+	2021 Form of Performance Vesting Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.5 of the Annual Report on Form 10-K (File 001-35700) filed by the Company with the SEC on February 25, 2021).
10.6+*	2022 Form of Time Vesting Restricted Stock Unit Award Agreement.
10.7+*	2022 Form of Performance-Vesting Restricted Stock Unit Agreement.
10.8+*	2023 Form of Time Vesting Restricted Stock Unit Award Agreement.
10.9+*	2023 Form of Performance-Vesting Restricted Stock Unit Agreement.
10.10+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.11+	Diamondback Energy, Inc. Amended and Restated Senior Management Severance Plan, adopted effective as of February 21, 2022 (including a form of participation agreement attached thereto as Schedule C) (incorporated by reference to Exhibit 10.9 of the Annual Report on Form 10-K (File 001-35700) filed by the Company with the SEC on February 24, 2022).
10.12+	Form of Participation Agreement (incorporated by reference from Schedule C-2 to Diamondback Energy, Inc. Senior Management Severance Plan filed as Exhibit 10.5 to the Company’s Annual Report on Form 10-K (File 001-35700) on February 27, 2020).
10.13	Executive Annual Incentive Compensation Plan adopted in February 2021 (incorporated by reference to Exhibit 10.11 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2021).
10.14	Second Amended and Restated Credit Agreement, dated as of November 1, 2013, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 5, 2013).
10.15	First Amendment, dated June 9, 2014, to the Second Amended and Restated Credit Agreement, originally dated November 1, 2013, by and among the Company, as parent guarantor, Diamondback O&G LLC, as borrower, each of the guarantors party thereto, each of the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 7, 2014).
10.16	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of November 13, 2014, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, the guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 18, 2014).
10.17	Third Amendment, dated as of June 21, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 27, 2016).
10.18	Fourth Amendment, dated as of December 15, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 20, 2016).
10.19	Fifth Amendment, dated as of November 28, 2017, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 4, 2017).
10.20	Eighth Amendment to the Second Amended and Restated Credit Agreement, dated as of October 26, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 1, 2018).

3. Exhibits

Exhibit Number	Description
10.21	Ninth Amendment to Second Amended and Restated Credit Agreement and Fourth Amendment to Amended and Restated Guaranty and Collateral Agreement, dated as of November 29, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 6, 2018).
10.22	Tenth Amendment to Second Amended and Restated Credit Agreement, dated as of March 25, 2019, between Diamondback, as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc. as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K (File No. 00 1-35700), filed by the Company with the SEC on March 29, 2019).
10.23	Eleventh Amendment to Second Amended and Restated Credit Agreement, dated as of June 28, 2019, between Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc. as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on July 3, 2019).
10.24	Twelfth Amendment to Second Amended and Restated Credit Agreement and First Amendment to Second Amended and Restated Guaranty Agreement, dated as of June 2, 2021, between Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 8, 2021).
10.25	Thirteenth Amendment to Second Amended and Restated Credit Agreement, dated as of June 2, 2022, between Diamondback Energy, Inc., as parent guarantor, Diamondback E&P LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 7, 2022).
10.26	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 Current Report on Form 8-K (File 001-36505) filed by Viper Energy Partners LP on July 26, 2018).
10.27	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 Viper Energy Partners LP's Form 8-K (File 001-36505) filed on September 30, 2019).
10.28	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 Viper Energy Partners LP's Form 8-K (File 001-36505) filed on October 10, 2019).
10.29	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).
10.30	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).
10.31	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 001-36505) filed on November 12, 2020).
10.32	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 Viper Energy Partners LP's Current Report on Form 8-K (File No. 001-36505) filed on November 18, 2021).
10.33	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 Viper Energy Partners LP's Annual Report on Form 10-K (File 001-36505) filed on February 23, 2023).

3. Exhibits

Exhibit Number	Description
21.1*	Subsidiaries of the Registrant.
22.1	List of Issuers and Guarantors Subsidiaries (incorporated by reference to Exhibit 22.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 5, 2021).
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P. with respect to the audit of Diamondback Energy, Inc. estimated reserves.
23.3*	Consent of Ryder Scott Company, L.P. with respect to the audit of Viper Energy Partners LP estimated reserves.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant 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.
32.2**	Certification of Chief Financial Officer of the Registrant 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.
99.1*	Audit Report of Ryder Scott Company, L.P., dated January 5, 2023, with respect to an audit of the proved reserves, future production and income attributable to certain leasehold interests of Diamondback Energy, Inc. as of December 31, 2022.
99.2*	Audit Report of Ryder Scott Company, L.P., dated January 5, 2023, with respect to an audit of the proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP, a subsidiary of Diamondback Energy, Inc., as of December 31, 2022.
101	The following financial information from the Company's Annual Report on Form 10-K for the year ended December 31, 2022, 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.

** The certifications attached as Exhibit 32.1 and Exhibit 32.2 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.

\+ Management contract, compensatory plan or arrangement.

\# The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally 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 report to be signed on its behalf by the undersigned thereunto duly authorized.

DIAMONDBACK ENERGY, INC.

Date: February 23, 2023

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities and Exchange Act of 1934, this 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/ Travis D. Stice Travis D. Stice	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	February 23, 2023
/s/ Vincent K. Brooks Vincent K. Brooks	Director	February 23, 2023
/s/ Michael P. Cross Michael P. Cross	Director	February 23, 2023
/s/ David L. Houston David L. Houston	Director	February 23, 2023
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 23, 2023
/s/ Stephanie K. Mains Stephanie K. Mains	Director	February 23, 2023
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 23, 2023
/s/ Melanie M. Trent Melanie M. Trent	Director	February 23, 2023
/s/ Frank D. Tsuru Frank D. Tsuru	Director	February 23, 2023
/s/ Steven E. West Steven E. West	Director	February 23, 2023
/s/ Kaes Van't Hof Kaes Van't Hof	President and Chief Financial Officer (Principal Financial Officer)	February 23, 2023
/s/ Teresa L. Dick Teresa L. Dick	Chief Accounting Officer, Executive Vice President and Assistant Secretary (Principal Accounting Officer)	February 23, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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 23, 2023 expressed an unqualified opinion.

Basis for opinion

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

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

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of 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 acquisition of FireBird's oil and natural gas properties

As described further in Note 2 to the 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 record depletion expense. Additionally, as described in Note 4 to the financial statements, the Company acquired significant oil and natural gas properties during the year through the FireBird Acquisition. 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 Company's development plan. In addition, the estimation of proved reserves is also 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 also utilizes an estimated fair value pricing model in determining the corresponding value of proved reserves. We identified the estimation of proved reserves attributable to oil and natural gas properties, including acquired proved reserves in the FireBird Acquisition, due to its impact on depletion expense and acquisition accounting, as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is 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 acquired oil and natural gas properties. 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 estimating depletion expense and management's estimation of the fair value of the acquired oil and natural gas properties in the FireBird Acquisition. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company's accounting records, the information provided to the reservoir engineering specialists, and the final proved reserve report and the final fair value reserve reports related to the acquired oil and natural gas properties prepared by the Company's specialists.

- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared and reviewed by the Company's 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 actual realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;

  - Tested operating cost inputs by comparing the forecasted amount to historical actual costs and reconciling any material differences;

  - Assessed the reasonableness of forecasted capital expenditures by comparing drilling forecasts applied in the reserve report to recent, actual drilling costs and evaluated any differences;

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

  - Obtained evidence supporting the amount of development of proved undeveloped properties reflected in the reserve report and compared future development plans to historical conversion rates to evaluate the Company's intent to develop the proved undeveloped properties;

  - Evaluated the estimated ultimate recovery of proved undeveloped properties by comparing forecasted amounts on a sample of individual wells to the estimated ultimate recovery of comparable proved developed producing 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 properties in the FireBird Acquisition and tested management's process of determining the significant inputs and assumptions, as follows:

  - Utilized a valuation specialist to evaluate the appropriateness of fair value pricing used in the fair value reserve report by comparing the pricing forecast to published product pricing on the acquisition closing date;

  - Utilized a valuation specialist to evaluate whether the Company's valuation methodology was reasonable and for certain inputs and assumptions, evaluated the process used to develop the estimate and developed an independent expectation of the estimate to evaluate its reasonableness;

  - Evaluated the appropriateness of the future operating cost and capital expenditure assumptions used in the fair value reserve report by comparing forecasted amounts to historical operating costs and capital expenditures of similarly located properties;

  - Compared, on a sample basis, the working and net revenue interests used in the fair value reserve report to the purchase and sale agreement;

– Evaluated, on a sample basis, the appropriateness of management's estimated future production volumes and the production decline curves by comparing to analogous operated wells; and

– Compared the unproved acreage value allocated, on a per acre basis, to other recent acquisitions in the same or similar locations.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2009.

Oklahoma City, Oklahoma
February 23, 2023

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
	2022	2021
	(In millions, except par value and share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 157	$ 654
Restricted cash	7	18
Accounts receivable:		
Joint interest and other, net	104	72
Oil and natural gas sales, net	618	598
Inventories	67	62
Derivative instruments	132	13
Income tax receivable	284	1
Prepaid expenses and other current assets	23	28
Total current assets	1,392	1,446
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($8,355 million and $8,496 million excluded from amortization at December 31, 2022 and December 31, 2021, respectively)	37,122	32,914
Other property, equipment and land	1,481	1,250
Accumulated depletion, depreciation, amortization and impairment	(14,844)	(13,545)
Property and equipment, net	23,759	20,619
Funds held in escrow	119	12
Equity method investments	566	613
Assets held for sale	158	—
Derivative instruments	23	4
Deferred income taxes, net	64	40
Investment in real estate, net	86	88
Other assets	42	76
Total assets	$ 26,209	$ 22,898
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 127	$ 36
Accrued capital expenditures	480	295
Current maturities of long-term debt	10	45
Other accrued liabilities	399	419
Revenues and royalties payable	619	452
Derivative instruments	47	174
Income taxes payable	34	17
Total current liabilities	1,716	1,438
Long-term debt	6,238	6,642
Derivative instruments	148	29
Asset retirement obligations	336	166
Deferred income taxes	2,069	1,338
Other long-term liabilities	12	40
Total liabilities	10,519	9,653
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Common stock, $0.01 par value; 400,000,000 shares authorized; 179,840,797 and 177,551,347 shares issued and outstanding at December 31, 2022 and December 31, 2021, respectively	2	2
Additional paid-in capital	14,213	14,084
Retained earnings (accumulated deficit)	801	(1,998)
Accumulated other comprehensive income (loss)	(7)	—
Total Diamondback Energy, Inc. stockholders' equity	15,009	12,088
Non-controlling interest	681	1,157
Total equity	15,690	13,245
Total liabilities and equity	$ 26,209	$ 22,898

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations and Comprehensive Income

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts, shares in thousands)		
Revenues:			
Oil sales	$ 7,660	$ 5,396	$ 2,410
Natural gas sales	858	569	107
Natural gas liquid sales	1,048	782	239
Other operating income	77	50	57
Total revenues	9,643	6,797	2,813
Costs and expenses:			
Lease operating expenses	652	565	425
Production and ad valorem taxes	611	425	195
Gathering and transportation	258	212	140
Depreciation, depletion, amortization and accretion	1,344	1,275	1,311
Impairment of oil and natural gas properties	—	—	6,021
General and administrative expenses	144	146	88
Merger and integration expenses	14	78	—
Other operating expenses	112	95	109
Total costs and expenses	3,135	2,796	8,289
Income (loss) from operations	6,508	4,001	(5,476)
Other income (expense):			
Interest expense, net	(159)	(199)	(197)
Other income (expense), net	(5)	(10)	(7)
Gain (loss) on derivative instruments, net	(586)	(848)	(81)
Gain (loss) on sale of equity method investments	—	23	—
Gain (loss) on extinguishment of debt	(99)	(75)	(5)
Income (loss) from equity investments	77	15	(10)
Total other income (expense), net	(772)	(1,094)	(300)
Income (loss) before income taxes	5,736	2,907	(5,776)
Provision for (benefit from) income taxes	1,174	631	(1,104)
Net income (loss)	4,562	2,276	(4,672)
Net income (loss) attributable to non-controlling interest	176	94	(155)
Net income (loss) attributable to Diamondback Energy, Inc.	$ 4,386	$ 2,182	$ (4,517)
Earnings (loss) per common share:			
Basic	$ 24.61	$ 12.24	$ (28.61)
Diluted	$ 24.61	$ 12.24	$ (28.61)
Weighted average common shares outstanding:			
Basic	176,539	176,643	157,976
Diluted	176,539	176,643	157,976
Dividends declared per share	$ 11.3100	$ 1.9500	$ 1.5250
Comprehensive income (loss):			
Net income (loss) attributable to Diamondback Energy, Inc.	$ 4,386	$ 2,182	$ (4,517)
Other comprehensive income (loss), net of tax:			
Pension and postretirement benefit plans	(7)	—	—
Comprehensive income (loss) attributable to Diamondback Energy, Inc	$ 4,379	$ 2,182	$ (4,517)

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	Shares	Amount					
	($ in millions, shares in thousands)						
Balance at December 31, 2019	159,002	$ 2	$ 12,357	$ 890	$ —	$ 1,657	$ 14,906
Unit-based compensation	—	—	—	—	—	10	10
Distribution equivalent rights payments	—	—	—	(1)	—	(2)	(3)
Stock-based compensation	—	—	43	—	—	—	43
Cash paid for tax withholding on vested equity awards	—	—	(5)	—	—	(2)	(7)
Repurchased shares under buyback program	(1,280)	—	(98)	—	—	—	(98)
Repurchased units under buyback programs	—	—	—	—	—	(39)	(39)
Distributions to non-controlling interest	—	—	—	—	—	(93)	(93)
Dividend paid	—	—	—	(236)	—	—	(236)
Exercise of stock and unit options and awards of restricted stock	366	—	1	—	—	—	1
Change in ownership of consolidated subsidiaries, net	—	—	358	—	—	(366)	(8)
Net income	—	—	—	(4,517)	—	(155)	(4,672)
Balance at December 31, 2020	158,088	2	12,656	(3,864)	—	1,010	9,804
Issuance of common units - Viper Energy Partners LP	—	—	—	—	—	337	337
Unit-based compensation	—	—	—	—	—	11	11
Distribution equivalent rights payments	—	—	—	(4)	—	(2)	(6)
Common stock issued for acquisitions	22,795	—	1,727	—	—	—	1,727
Stock-based compensation	—	—	60	—	—	—	60
Cash paid for tax withholding on vested equity awards	—	—	(6)	—	—	(2)	(8)
Repurchased shares under buyback program	(4,128)	—	(431)	—	—	—	(431)
Repurchased units under buyback programs	—	—	—	—	—	(94)	(94)
Distributions to non-controlling interest	—	—	—	—	—	(112)	(112)
Dividend paid	—	—	—	(312)	—	—	(312)
Exercise of stock options and vesting of restricted stock units	796	—	12	—	—	—	12
Change in ownership of consolidated subsidiaries, net	—	—	66	—	—	(85)	(19)
Net income (loss)	—	—	—	2,182	—	94	2,276
Balance at December 31, 2021	177,551	2	14,084	(1,998)	—	1,157	13,245
Unit-based compensation	—	—	—	—	—	8	8
Distribution equivalent rights payments	—	—	—	(15)	—	(1)	(16)
Stock-based compensation	4	—	68	—	—	—	68
Cash paid for tax withholding on vested equity awards	(11)	—	(16)	—	—	(3)	(19)
Repurchased shares under buyback program	(8,694)	—	(1,098)	—	—	—	(1,098)
Repurchased units under buyback programs	—	—	—	—	—	(153)	(153)
Common stock issued for acquisition	10,273	—	1,220	—	—	(344)	876
Distributions to non-controlling interest	—	—	—	—	—	(217)	(217)
Dividend paid	—	—	—	(1,572)	—	—	(1,572)
Exercise of stock options and issuance of restricted stock units and awards	718	—	1	—	—	—	1
Change in ownership of consolidated subsidiaries, net	—	—	(46)	—	—	58	12
Other comprehensive income (loss), net of tax	—	—	—	—	(7)	—	(7)
Net income (loss)	—	—	—	4,386	—	176	4,562
Balance at December 31, 2022	179,841	$ 2	$ 14,213	$ 801	$ (7)	$ 681	$ 15,690

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Cash flows from operating activities:			
Net income (loss)	$ 4,562	$ 2,276	$ (4,672)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Provision for (benefit from) deferred income taxes	720	606	(1,042)
Impairment of oil and natural gas properties	—	—	6,021
Depreciation, depletion, amortization and accretion	1,344	1,275	1,311
(Gain) loss on extinguishment of debt	99	75	5
(Gain) loss on derivative instruments, net	586	848	81
Cash received (paid) on settlement of derivative instruments	(850)	(1,247)	250
(Income) loss from equity investment	(77)	(15)	10
Equity-based compensation expense	55	51	37
(Gain) loss on sale of equity method investments	—	(23)	—
Other	85	62	20
Changes in operating assets and liabilities:			
Accounts receivable	(47)	(196)	217
Income tax receivable	(283)	152	(62)
Prepaid expenses and other	21	20	2
Accounts payable and accrued liabilities	(47)	(41)	(20)
Income tax payable	17	—	—
Revenues and royalties payable	156	148	(41)
Other	(16)	(47)	1
Net cash provided by (used in) operating activities	6,325	3,944	2,118
Cash flows from investing activities:			
Drilling, completions and infrastructure additions to oil and natural gas properties	(1,854)	(1,457)	(1,719)
Additions to midstream assets	(84)	(30)	(140)
Property acquisitions	(1,567)	(827)	(198)
Funds held in escrow	(108)	40	(51)
Proceeds from sale of assets	327	820	63
Other	(44)	(85)	(56)
Net cash provided by (used in) investing activities	(3,330)	(1,539)	(2,101)
Cash flows from financing activities:			
Proceeds from borrowings under credit facilities	5,204	1,313	1,130
Repayments under credit facilities	(5,551)	(1,000)	(1,478)
Proceeds from senior notes	2,500	2,200	997
Repayment of senior notes	(2,410)	(3,193)	(239)
Proceeds from (repayments to) joint venture	(74)	(20)	40
Premium on extinguishment of debt	(63)	(178)	(2)
Repurchased shares under buyback program	(1,098)	(431)	(98)
Repurchased units under buyback program	(153)	(94)	(39)
Dividends paid to stockholders	(1,572)	(312)	(236)
Distributions to non-controlling interest	(217)	(112)	(93)
Financing portion of net cash received (paid) for derivative instruments	—	22	—
Other	(69)	(36)	(19)
Net cash provided by (used in) financing activities	(3,503)	(1,841)	(37)
Net increase (decrease) in cash and cash equivalents	(508)	564	(20)
Cash, cash equivalents and restricted cash at beginning of period	672	108	128
Cash, cash equivalents and restricted cash at end of period	$ 164	$ 672	$ 108

See accompanying notes to consolidated financial statements.

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc., together with its subsidiaries (collectively referred to as ("Diamondback" or the "Company" unless the context otherwise requires) is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas.

The wholly-owned subsidiaries of Diamondback, as of December 31, 2022, include Diamondback E&P LLC ("Diamondback E&P"), a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company ("Viper's General Partner"), Rattler Midstream GP LLC, a Delaware limited liability company ("Rattler's GP"), Rattler Midstream LP, a Delaware limited partnership ("Rattler"), and QEP Resources, Inc. ("QEP"), a Delaware Corporation. Diamondback O&G LLC ("O&G"), Energen Corporation ("Energen"), Energen Resources Corporation and EGN Services, Inc., former wholly owned subsidiaries of Diamondback, were merged with and into Diamondback E&P LLC effective June 30, 2021 as part of the internal restructuring of the Company's subsidiaries (the "E&P Merger").

Rattler Merger

On August 24, 2022 (the "Effective Date"), the Company completed the merger with Rattler pursuant to which the Company acquired all of the approximately 38.51 million publicly held outstanding common units of Rattler in exchange for approximately 4.35 million shares of the Company's common stock (the "Rattler Merger"). Rattler continued as the surviving entity. Following the Rattler Merger, the Company owned all of Rattler's outstanding common units and Class B units, and Rattler GP remained the general partner of Rattler. Following the closing of the Rattler Merger, Rattler's common units were delisted from the NASDAQ Global Select Market and Rattler filed a certification on Form 15 with the SEC requesting the deregistration of its common units and suspension of Rattler's reporting obligations under the Exchange Act.

The Rattler Merger was accounted for as a non-cash equity transaction resulting in increases to common stock of $44 thousand, additional paid-in-capital of $344 million, and merger and integration expense of $11 million, and a decrease in noncontrolling interests in consolidated subsidiaries of $344 million. For periods prior to the Effective Date, the results of operations attributable to the non-controlling interest in Rattler are presented within equity and net income and are shown separately from the equity and net income attributable to the Company.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

Diamondback's publicly traded subsidiary, Viper, is consolidated in the financial statements of the Company. As of December 31, 2022, the Company owned approximately 56% of Viper's total units outstanding. The Company's wholly owned subsidiary, Viper Energy Partners GP LLC, is the general partner of Viper. The results of operations attributable to the non-controlling interest in Viper are presented within equity and net income and are shown separately from the equity and net income attributable to the Company.

The Company has two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) the midstream operations segment, which is focused on owning, operating, developing and acquiring midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Prior to the Rattler Merger, both the upstream operations segment and the midstream operations segment were also considered reportable segments. Following the Rattler Merger, the Company determined only the upstream operations segment met the quantitative requirements of a reportable segment.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial 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 consolidated 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 consolidated 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 consolidated financial statements. Actual results could differ from those estimates.

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 effects of COVID-19, the war in Ukraine and actions by OPEC members and other exporting nations on the supply and demand in global oil and natural gas markets continued to contribute to economic and pricing volatility. The financial results of companies in the oil and natural gas industry have been impacted materially as a result of these events and changing market conditions. Such circumstances generally increase the 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 the particular circumstances. 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 properties, fair value estimates of derivative instruments, the fair value determination of acquired assets and liabilities assumed, and estimates of income taxes, including deferred tax valuation allowances.

Cash, Cash Equivalents and Restricted Cash

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents. 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.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for expected losses as estimated by the Company when collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable from joint interest owners or purchasers outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance for each type of receivable utilizing the loss-rate method, which considers a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for expected losses. At December 31, 2022 and 2021, the Company's allowances for credit losses related to joint interest receivables and credit losses related to sales of oil and natural gas production were not material.

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. For commodity derivative instruments and interest rate swaps which have not been designated as hedges for accounting purposes, the Company 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. From the second quarter of 2021 through the second quarter of 2022, the Company had certain interest rate swaps designated as fair value hedges under the "shortcut" method of accounting. As such, gains and losses due to changes in the fair value of the interest rate swaps during those periods completely offset changes in the fair value of the hedged portion of the underlying debt. In the second quarter of 2022, the Company elected to fully dedesignate these interest rate swaps and hedge accounting was discontinued. For additional information regarding the Company's derivative instruments, see Note 12—Derivatives.

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, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. Costs, including related employee costs, associated with production and operation of the properties are charged to expense as incurred. All other internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. 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 and natural liquids. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $8.87, $8.77 and $11.30 for the years ended December 31, 2022, 2021 and 2020, respectively. Depletion expense for oil and natural gas properties was $1.3 billion, $1.2 billion and $1.2 billion for the years ended December 31, 2022, 2021 and 2020, respectively.

Under this 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 cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) 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, (b) the cost of properties not being amortized, if any, and (c) 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. For additional information regarding the Company's impairments on proved oil and natural gas properties, see Note 5—Property and Equipment.

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 on at least an annual basis 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 to drill; remaining lease term; 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.

Other Property, Equipment and Land

Other property, equipment and land is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight-line method over their estimated useful lives, which range from three to 30 years.

Equity Method Investments

The Company accounts for its corporate joint ventures under the equity method of accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification ("ASC") Topic 323 "Investments — Equity Method and Joint Ventures." The Company applies the equity method of accounting to investments of less than 50% in an investee over which the Company exercises significant influence but does not have control, and investments of greater than 50% in an investee over which the Company does not exercise significant influence or have control. Under the equity method of accounting, the Company's share of the investee's earnings or loss is recognized in the statement of operations. As of December 31, 2022, the Company's proportionate share of the income or loss from equity method investments is recognized on a one or two-month lag for its equity method investments.

Judgment regarding the level of influence over each equity method investment includes considering key factors such as ownership interest, representation on the board of directors, participation in policy-making decisions, material intercompany transactions and extent of ownership by an investor in relation to the concentration of other shareholdings. Additionally, an investment in a limited liability company that maintains a specific ownership account for each investor shall be viewed as similar to an investment in a limited partnership for purposes of determining whether a non-controlling investment shall be accounted for using the cost method or the equity method.

The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such a loss has occurred, the Company recognizes an impairment provision. There were no material impairments of the Company's equity investments for the years ended December 31, 2022, 2021 and 2020. See Note 7—Equity Method Investments for further details.

Investments in Real Estate

The Company has invested in certain real estate assets which are stated at cost, less accumulated depreciation and amortization. The Company considers the period of future benefit of each respective asset to determine the appropriate useful life and depreciation and amortization is calculated using the straight-line method over the assigned useful life.

Upon acquisition of real estate properties, the purchase price is allocated to tangible assets, consisting of land and building, and to identified intangible assets and liabilities, which may include the value of above market and below market leases and the value of in-place leases. The allocation of the purchase price is based upon the fair value of each component of the property. Although independent appraisals may be used to assist in the determination of fair value, in many cases these values will be based upon management's assessment of each property, the selling prices of comparable properties and the discounted value of cash flows from the asset.

Investments in real estate, excluding insignificant unamortized in-place lease and above-market lease intangibles, consist of the following:

		December 31,	
	Estimated Useful Lives	**2022**	**2021**
	(Years)	**(In millions)**	
Buildings	20-30	$ 96	$ 95
Tenant improvements	5 - 13	5	4
Land	N/A	1	1
Land improvements	5 - 15	1	1
Total real estate assets		103	101
Less: accumulated depreciation		(20)	(16)
Total investment in land and buildings, net		$ 83	$ 85

Asset Retirement Obligations

The Company measures the future cost to retire its tangible long-lived assets and recognizes such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

Asset retirement obligations represent the future abandonment costs of tangible assets, namely wells. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount or if there is a change in the estimated liability, the difference is recorded in oil and natural gas properties.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with the future plugging and abandonment of wells and related facilities. For additional information regarding the Company's asset retirement obligations, see Note 6—Asset Retirement Obligations.

Impairment of Long-Lived Assets

Other property and equipment used in operations and midstream assets are reviewed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its estimated future undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no significant impairment losses for the years ended December 31, 2022, 2021 and 2020.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these unevaluated properties to their intended use. Capitalized interest cannot exceed gross interest expense. See Note 8—Debt for further details.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of tubular goods and equipment at December 31, 2022 and 2021. The Company's tubular goods and equipment are primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units.

Debt Issuance Costs

Long-term debt includes capitalized costs related to the senior notes, net of accumulated amortization. The costs associated with the senior notes are netted against the senior notes balances and are amortized over the term of the senior notes using the effective interest method. See Note 8—Debt for further details. The costs associated with the Company's credit facilities are included in other assets on the consolidated balance sheet and are amortized over the term of the facility.

Other Accrued Liabilities

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

Other accrued liabilities consist of the following at December 31, 2022, and 2021:

	December 31,	
	2022	2021
	(In millions)	
Derivative liability payable	$ 21	$ 101
Lease operating expenses payable	131	86
Ad valorem taxes payable	108	70
Accrued compensation	35	48
Interest payable	49	46
Midstream operating expenses payable	15	13
Liability for drilling costs prepaid by joint interest partners	1	10
Other	39	45
Total other accrued liabilities	$ 399	$ 419

Revenue and Royalties Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds that the Company has not yet distributed to other revenue and royalty owners are reflected as revenue and royalties payable in the accompanying consolidated balance sheets. The Company recognizes revenue for only its net revenue interest in oil and natural gas properties.

Non-controlling Interests

Non-controlling interests in the accompanying consolidated financial statements represent minority interest ownership in Viper and are presented as a component of equity. When the Company’s relative ownership interests in Viper change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur. Because these changes in the ownership interests in Viper do not result in a change of control, the transactions are accounted for as equity transactions under ASC Topic 810, “Consolidation”, which requires that any differences between the carrying value of the Company’s basis in Viper and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. See Note 9—Stockholders' Equity and Earnings Per Share for a discussion of changes of the Company’s ownership interest in consolidated subsidiaries during the years ended December 31, 2022, 2021 and 2020.

Revenue Recognition

Revenue from Contracts with Customers

Sales of oil, natural gas and natural gas liquids are recognized at the point control of the product is transferred to the customer. Virtually all of the pricing provisions in the Company’s contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies.

Oil sales

The Company’s oil sales contracts are generally structured where it delivers oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company or a third party transports the product to the delivery point and receives a specified index price from the purchaser with no deduction. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company’s consolidated statements of operations.

Natural gas and natural gas liquids sales

Under the Company's natural gas processing contracts, it delivers natural gas to a midstream processing entity at the wellhead, battery facilities or the inlet of the midstream processing entity's system. Generally, the midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of natural gas liquids and residue gas. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation, gathering, processing, treating and compression fees presented as an expense in its consolidated statements of operations.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or natural gas liquids in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing, treating and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing, treating and compression expense in its consolidated statements of operations.

Transaction price allocated to remaining performance obligations

The Company's upstream product sales contracts do not originate until production occurs and, therefore, are not considered to exist beyond each days' production. Therefore, there are no remaining performance obligations under any of our product sales contracts.

Under its revenue agreements, each delivery generally represents a separate performance obligation; therefore, future volumes delivered are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company's product sales contracts, it has the right to invoice its customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, purchaser and settlement statements for 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 production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the years ended December 31, 2022, 2021 and 2020 revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. 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 revenue related to expected sales volumes and prices for those properties are estimated and recorded.

Accounting for Equity-Based Compensation

The Company has granted various types of stock-based awards including stock options and restricted stock units. Viper and Rattler have granted various unit-based awards including unit options and phantom units to employees, officers and directors of Viper's General Partner, Rattler's GP and the Company who perform services for the respective entities. These plans and related accounting policies for material awards are defined and described more fully in Note 10—Equity-

Based Compensation. Equity compensation awards are measured at fair value on the date of grant and are expensed over the required service period. Forfeitures for these awards are recognized as they occur.

Environmental Compliance and Remediation

Environmental compliance and remediation costs, including ongoing maintenance and monitoring, are expensed as incurred. Liabilities are accrued when environmental assessments and remediation are probable, and the costs can be reasonably estimated.

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. For additional information regarding income taxes, see Note 11—Income Taxes.

Accumulated Other Comprehensive Income

The following table provides changes in the components of accumulated other comprehensive income, net of related income tax effects related to insignificant pension and postretirement benefit plans the Company acquired from Energen and QEP (in millions):

Balance as of December 31, 2021	$	—
Net actuarial gain (loss) on pension and postretirement benefit plans		(9)
Income tax benefit (expense)		2
Balance as of December 31, 2022	$	(7)

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848) – Deferral of the Sunset Date of Topic 848." This update extended the use of the optional expedient through December 31, 2024. The Company adopted this update effective December 31, 2022. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In October 2021, the FASB issued ASU 2021-08, "Business Combinations (Topic 805) – Accounting for Contract Assets and Contract Liabilities from Contracts with Customers." This update requires the acquirer in a business combination to record contract asset and liabilities following Topic 606 – "Revenue from Contracts with Customers" at acquisition as if it had originated the contract, rather than at fair value. This update is effective for public business entities for fiscal years and interim periods beginning after December 15, 2022, with early adoption permitted. The Company continues to evaluate the provisions of this update, but does not believe the adoption will have a material impact on its 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, the effects of adoption are not expected to be material or are clarifications of ASUs previously disclosed.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue from Contracts with Customers

The following tables present the Company's revenue from contracts with customers disaggregated by product type and basin:

	Year Ended December 31, 2022			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 5,541	$ 2,107	$ 12	$ 7,660
Natural gas sales	563	292	3	858
Natural gas liquid sales	719	327	2	1,048
Total	$ 6,823	$ 2,726	$ 17	$ 9,566

	Year Ended December 31, 2021			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 3,468	$ 1,663	$ 265	$ 5,396
Natural gas sales	327	215	27	569
Natural gas liquid sales	493	249	40	782
Total	$ 4,288	$ 2,127	$ 332	$ 6,747

	Year Ended December 31, 2020			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 1,393	$ 1,011	$ 6	$ 2,410
Natural gas sales	56	50	1	107
Natural gas liquid sales	138	100	1	239
Total	$ 1,587	$ 1,161	$ 8	$ 2,756

Customers

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the year ended December 31, 2022, two purchasers each accounted for more than 10% of our revenue: Vitol Inc. ("Vitol") (23%) and Shell Trading (USA) Company ("Shell") (20%). For the year ended December 31, 2021, three purchasers each accounted for more than 10% of the Company's revenue: Vitol (21%); Shell (19%); and Plains Marketing, L.P. ("Plains") (12%). For the year ended December 31, 2020, four purchasers each accounted for more than 10% of the Company's revenue: Vitol (26%); Shell (22%); Plains (20%); and Trafigura Trading LLC (11%). The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

4. ACQUISITIONS AND DIVESTITURES

2022 Activity

FireBird Energy LLC

On November 30, 2022, the Company closed on its acquisition of all leasehold interests and related assets of FireBird Energy LLC, which included approximately 75,000 gross (68,000 net) acres in the Midland Basin and certain related oil and gas assets, in exchange for 5.92 million shares of the Company's common stock and $787 million in cash, including certain customary closing adjustments. The cash portion of the consideration for the FireBird Acquisition was funded through a combination of cash on hand and borrowings under the Company's revolving credit facility. As a result of the FireBird Acquisition, the Company added approximately 854 gross producing wells.

The following table presents the acquisition consideration paid in the FireBird Acquisition (in millions, except per share data, shares in thousands):

Consideration:		
Shares of Diamondback common stock issued at closing		5,921
Closing price per share of Diamondback common stock on the closing date	$	148.02
Fair value of Diamondback common stock issued	$	876
Cash consideration		787
Total consideration (including fair value of Diamondback common stock issued)	$	1,663

Purchase Price Allocation

The FireBird Acquisition has been accounted for as a business combination using the acquisition method. The following table represents the allocation of the total purchase price paid in the FireBird Acquisition to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. Although the purchase price allocation is substantially complete as of the date of this filing, there may be further adjustments to the fair value of certain assets acquired and liabilities assumed, including but not limited to the Company's oil and natural gas properties. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date and may revise the value of the assets and liabilities as appropriate within that time frame.

The following table sets forth the Company's preliminary purchase price allocation (in millions):

Total consideration	$	1,663
Fair value of liabilities assumed:		
Other long-term liabilities		10
Fair value of assets acquired:		
Oil and natural gas properties		1,558
Inventories		1
Other property, equipment and land		114
Amount attributable to assets acquired		1,673
Net assets acquired and liabilities assumed	$	1,663

Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of acquired midstream assets was based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets and were included in the Company's consolidated balance sheets under the caption "Other property, equipment and land." The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and are therefore considered Level 3 inputs.

With the completion of the FireBird Acquisition, the Company acquired proved properties of $648 million and unproved properties of $910 million. The results of operations attributable to the FireBird Acquisition since the acquisition date have been included in the consolidated statements of operations and include $46 million of total revenue and $28 million of net income for the year ended December 31, 2022.

Delaware Basin Acquisition

On January 18, 2022, the Company acquired, from an unrelated third-party seller, approximately 6,200 net acres in the Delaware Basin for $232 million in cash, including customary closing adjustments. The acquisition was funded through cash on hand.

Other 2022 Acquisitions

Additionally during the year ended December 31, 2022, the Company acquired, from unrelated third-party sellers, approximately 4,000 net acres and over 200 gross wells in the Permian Basin for an aggregate purchase price of approximately $220 million in cash, including customary closing adjustments. The acquisitions were funded through cash on hand.

Divestitures of Certain Non-Core Assets

In October 2022, the Company completed the divestiture of non-core Delaware Basin acreage consisting of approximately 3,272 net acres, with net production of approximately 550 BO/d (800 BOE/d) for $155 million of net proceeds. The Company used the net proceeds from this transaction towards debt reduction.

See Note 16 — Subsequent Events for transactions entered into in the first quarter of 2023.

2021 Activity

Guidon Operating LLC

On February 26, 2021, the Company closed on its acquisition of all leasehold interests and related assets of Guidon Operating LLC (the "Guidon Acquisition"), which included approximately 32,500 net acres in the Northern Midland Basin in exchange for 10.68 million shares of the Company's common stock and $375 million of cash. The cash portion of the consideration for the Guidon Acquisition was funded through a combination of cash on hand and borrowings under the Company's credit facility. As a result of the Guidon Acquisition, the Company added approximately 210 gross producing wells.

The following table presents the acquisition consideration paid in the Guidon Acquisition (in millions, except per share data, shares in thousands):

Consideration:		
Shares of Diamondback common stock issued at closing		10,676
Closing price per share of Diamondback common stock on the closing date	$	69.28
Fair value of Diamondback common stock issued	$	740
Cash consideration		375
Total consideration (including fair value of Diamondback common stock issued)	$	1,115

Purchase Price Allocation

The Guidon Acquisition has been accounted for as a business combination using the acquisition method. The following table represents the allocation of the total purchase price paid in the Guidon Acquisition to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. The purchase price allocation was completed in the first quarter of 2022.

The following table sets forth the Company's purchase price allocation (in millions):

Total consideration	$	1,115
Fair value of liabilities assumed:		
Asset retirement obligations		9
Fair value of assets acquired:		
Oil and natural gas properties		1,110
Midstream assets		14
Amount attributable to assets acquired		1,124
Net assets acquired and liabilities assumed	$	1,115

Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of acquired midstream assets was based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets. The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and are therefore considered Level 3 inputs.

With the completion of the Guidon Acquisition, the Company acquired proved properties of $537 million and unproved properties of $573 million. The results of operations attributable to the Guidon Acquisition from the acquisition date through December 31, 2021 have been included in the consolidated statements of operations and include $345 million of total revenue and $170 million of net income.

QEP Resources, Inc.

On March 17, 2021, the Company completed its acquisition of QEP in an all-stock transaction (the "QEP Merger"). The addition of QEP's assets increased the Company's net acreage in the Midland Basin by approximately 49,000 net acres. Under the terms of the QEP Merger, each eligible share of QEP common stock issued and outstanding immediately prior to the effective time converted into the right to receive 0.050 of a share of Diamondback common stock, with cash being paid in lieu of any fractional shares (the "merger consideration"). At the closing date of the QEP Merger, the carrying value of QEP's outstanding debt was approximately $1.6 billion. See Note 8—Debt for further discussion.

The following table presents the acquisition consideration paid to QEP stockholders in the QEP Merger (in millions, except per share data, shares in thousands):

Consideration:		
Eligible shares of QEP common stock converted into shares of Diamondback common stock		238,153
Shares of QEP equity awards included in precombination consideration		4,221
Total shares of QEP common stock eligible for merger consideration		242,374
Exchange ratio		0.050
Shares of Diamondback common stock issued as merger consideration		12,119
Closing price per share of Diamondback common stock	$	81.41
Total consideration (fair value of the Company's common stock issued)	$	987

Purchase Price Allocation

The QEP Merger has been accounted for as a business combination using the acquisition method. The following table represents the preliminary allocation of the total purchase price for the acquisition of QEP to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date. The purchase price allocation was completed in the first quarter of 2022.

The following table sets forth the Company's purchase price allocation (in millions):

Total consideration	$	987
Fair value of liabilities assumed:		
Accounts payable - trade	$	26
Accrued capital expenditures		38
Other accrued liabilities		107
Revenues and royalties payable		67
Derivative instruments		242
Long-term debt		1,710
Asset retirement obligations		54
Other long-term liabilities		63
Amount attributable to liabilities assumed	$	2,307
Fair value of assets acquired:		
Cash, cash equivalents and restricted cash	$	22
Accounts receivable - joint interest and other, net		87
Accounts receivable - oil and natural gas sales, net		44
Inventories		18
Income tax receivable		33
Prepaid expenses and other current assets		7
Oil and natural gas properties		2,922
Other property, equipment and land		16
Deferred income taxes		39
Other assets		106
Amount attributable to assets acquired		3,294
Net assets acquired and liabilities assumed	$	987

The purchase price allocation above was based on estimates of the fair values of the assets and liabilities of QEP as of the closing date of the QEP Merger. The majority of the measurements of assets acquired and liabilities assumed were based on inputs that are not observable in the market and are therefore considered Level 3 inputs. The fair value of acquired property and equipment, including midstream assets classified in oil and natural gas properties, was based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets. Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of QEP's outstanding senior unsecured notes was based on unadjusted quoted prices in an active market, which are considered Level 1 inputs. The value of derivative instruments was based on observable inputs including forward commodity price curves which are considered Level 2 inputs. Deferred income taxes represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed.

With the completion of the QEP Merger, the Company acquired proved properties of $2.0 billion and unproved properties of $733 million, primarily in the Midland Basin and the Williston Basin. In October 2021, the Company completed the divestiture of the Williston Basin properties, acquired as part of the QEP Merger and consisting of approximately 95,000 net acres, to Oasis Petroleum Inc. for net cash proceeds of approximately $586 million, after customary closing adjustments. See "—Williston Basin Divestiture" below.

The results of operations attributable to the QEP Merger since the acquisition date have been included in the consolidated statements of operations and include $1.1 billion of total revenue and $455 million of net income for the year ended December 31, 2022.

Pro Forma Financial Information (Unaudited)

The following unaudited summary pro forma financial information for the years ended December 31, 2022, 2021 and 2020 has been prepared to give effect to the QEP Merger and the Guidon Acquisition as if they had occurred on January 1, 2020 and the FireBird Acquisition as if it occurred on January 1, 2021. The unaudited pro forma financial information does not purport to be indicative of what the combined company's results of operations would have been if these transactions had occurred on the dates indicated, nor is it indicative of the future financial position or results of operations of the combined company.

The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for QEP's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including adjustments to depreciation, depletion and amortization based on the full cost method of accounting and the purchase price allocated to property, plant, and equipment as well as adjustments to interest expense and the provision for (benefit from) income taxes.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of (i) $2 million for the FireBird Acquisition during the year ended December 31, 2022, (ii) $78 million for the QEP Merger and the Guidon Acquisition during the year ended December 31, 2021, and (iii) $31 million of costs incurred by QEP through the closing date of the QEP Merger. These acquisition-related costs primarily consist of one-time severance costs and the accelerated or change-in-control vesting of certain QEP share-based awards for former QEP employees based on the terms of the merger agreement relating to the QEP Merger and other bank, legal and advisory fees. The pro forma results of operations do not include any cost savings or other synergies that may result from the QEP Merger and the Guidon Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired assets. The pro forma financial data does not include the results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material.

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts)		
Revenues	$ 10,071	$ 7,198	$ 3,727
Income (loss) from operations	$ 6,770	$ 4,193	$ (5,771)
Net income (loss)	$ 4,648	$ 2,148	$ (4,641)
Basic earnings per common share	$ 25.25	$ 11.40	$ (25.67)
Diluted earnings per common share	$ 25.25	$ 11.40	$ (25.67)

Divestitures of Certain Non-Core Assets

On June 3, 2021 and June 7, 2021, respectively, the Company closed transactions to divest certain non-core Permian assets including over 7,000 net acres of non-core Southern Midland Basin acreage in Upton county, Texas and approximately 1,300 net acres of non-core, non-operated Delaware Basin assets in Lea county, New Mexico for combined net cash proceeds of $82 million, after customary closing adjustments. The Company used its net proceeds from these transactions toward debt reduction.

Williston Basin Divestiture

On October 21, 2021, the Company completed the divestiture of its Williston Basin oil and natural gas assets, consisting of approximately 95,000 net acres, to Oasis Petroleum Inc., for net cash proceeds of approximately $586 million, after customary closing adjustments. This transaction did not result in a significant alteration of the relationship between the Company's capitalized costs and proved reserves and, accordingly, the Company recorded the proceeds as a reduction of its full cost pool with no gain or loss recognized on the sale. The Company used its net proceeds from this transaction toward debt reduction.

Gas Gathering Assets Divestiture

On November 1, 2021, the Company completed the sale of certain gas gathering assets to Brazos Delaware Gas, LLC, an affiliate of Brazos Midstream ("Brazos"), for net cash proceeds of approximately $54 million, after customary closing adjustments.

2021 Drop Down Transaction

On December 1, 2021, Diamondback completed the sale of certain water midstream assets to Rattler in exchange for cash proceeds of approximately $164 million, in a drop down transaction (the "Drop Down"). The midstream assets consisted primarily of produced water gathering and disposal systems, produced water recycling facilities, and sourced water gathering and storage assets acquired by the Company through the Guidon Acquisition and the QEP Merger with a carrying value of approximately $164 million. The Company and Rattler also mutually amended their commercial agreements covering produced water gathering and disposal and sourced water gathering services to add certain Diamondback leasehold acreage to Rattler's dedication. The Drop Down transaction was accounted for as a transaction between entities under common control.

Viper's Swallowtail Acquisition

On October 1, 2021, Viper acquired certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC pursuant to a definitive purchase and sale agreement for 15.25 million of Viper's common units and approximately $225 million in cash (the "Swallowtail Acquisition"). The mineral and royalty interests acquired in the Swallowtail Acquisition represent approximately 2,313 net royalty acres primarily in the Northern Midland Basin, of which approximately 62% are operated by Diamondback. The Swallowtail Acquisition had an effective date of August 1, 2021. The cash portion of the consideration for the Swallowtail Acquisition was funded through a combination of Viper's cash on hand and approximately $190 million of borrowings under Viper LLC's revolving credit facility.

Rattler's WTG Joint Venture Acquisition

On October 5, 2021, Rattler and a private affiliate of an investment fund formed the WTG joint venture. Rattler contributed approximately $104 million in cash for a 25% membership interest in the WTG joint venture, which then completed the acquisition of a majority interest in WTG Midstream from West Texas Gas, Inc. and its affiliates. WTG Midstream's assets primarily consist of an interconnected gas gathering system and six major gas processing plants servicing the Midland Basin with 925 MMcf/d of total processing capacity with additional gas gathering and processing expansions planned.

Rattler's Gas Gathering Divestiture

On November 1, 2021, Rattler completed the sale of its gas gathering assets to Brazos for aggregate total gross potential consideration of $94 million, consisting of (i) $84 million due at closing, after customary closing adjustments, (ii) a $5 million contingent payment due in 2023 if the aggregate actual deliveries of gas volumes into the gas gathering system by and/or on behalf of the Company and its affiliates exceed certain specified thresholds during 2022, and (iii) a $5 million contingent payment due in 2024 if the aggregate actual deliveries of gas volumes into the gas gathering system by and/or on behalf of the Company and its affiliates exceed certain specified thresholds during 2022 and 2023. The contingent payments will be recorded if and when they become realizable.

See Note 16—Subsequent Events for discussion of acquisition and divestiture activity which occurred subsequent to December 31, 2022.

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31, 2022	December 31, 2021
	(In millions)	
Oil and natural gas properties:		
Subject to depletion	$ 28,767	$ 24,418
Not subject to depletion	8,355	8,496
Gross oil and natural gas properties	37,122	32,914
Accumulated depletion	(6,671)	(5,434)
Accumulated impairment	(7,954)	(7,954)
Oil and natural gas properties, net	22,497	19,526
Other property, equipment and land	1,481	1,250
Accumulated depreciation, amortization, accretion and impairment	(219)	(157)
Total property and equipment, net	$ 23,759	$ 20,619
Balance of costs not subject to depletion:		
Incurred in 2022	$ 1,142	
Incurred in 2021	1,435	
Incurred in 2020	71	
Prior	5,707	
Total not subject to depletion	$ 8,355	

Capitalized internal costs were approximately $58 million, $60 million and $53 million for the years ended December 31, 2022, 2021 and 2020, respectively. 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. Although the evaluation process has not been completed on our unevaluated properties, the Company currently estimates these costs will be added to the amortization base within ten years.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter which determines a limit, or ceiling, on the book value of proved oil and natural gas properties. No impairment expense was recorded for the years ended December 31, 2022 and 2021. The Company recorded non-cash ceiling test impairment for the year ended December 31, 2020 of $6.0 billion, which is included in accumulated depletion, depreciation, amortization and impairment on the consolidated balance sheet. The impairment charge affected the Company's reported net income (loss) but did not reduce its cash flow.

In connection with the QEP Merger and the Guidon Acquisition, the Company recorded the oil and natural gas properties acquired at fair value, based on forward strip oil and natural gas pricing existing at the closing date of the respective transactions, in accordance with ASC 820 Fair Value Measurement. Pursuant to SEC guidance, the Company determined that the fair value of the properties acquired in the QEP Merger and the Guidon Acquisition clearly exceeded the related full cost ceiling limitation beyond a reasonable doubt. As such, the Company requested and received a waiver from the SEC to exclude the properties acquired from the ceiling test calculation for the quarter ended March 31, 2021. As a result, no impairment expense related to the QEP Merger and the Guidon Acquisition was recorded for the three months ended March 31, 2021. Had the Company not received a waiver from the SEC, an impairment charge of approximately $1.1 billion would have been recorded for such period. Management affirmed there has not been a decline in the fair value of these acquired assets. The properties acquired in the QEP Merger and the Guidon Acquisition had total unamortized costs at March 31, 2021 of $3.0 billion and $1.1 billion, respectively.

In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices decline as compared to the commodity prices used in prior quarters, the Company may have material write downs in subsequent quarters. Given the rate of change impacting the oil and natural gas industry described above, it is possible that circumstances requiring additional impairment testing will occur in future interim periods, which could result in potentially material impairment charges being recorded.

At December 31, 2022, there were $126 million in exploration costs and development costs and $206 million in capitalized interest that are not subject to depletion. At December 31, 2021, there were $135 million in exploration and development costs and $124 million in capitalized interest costs that were not subject to depletion.

6. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligations liability for the following periods:

	Year Ended December 31,	
	2022	2021
	(In millions)	
Asset retirement obligations, beginning of period	$ 171	$ 109
Additional liabilities incurred	36	11
Liabilities acquired	19	65
Liabilities settled and divested	(26)	(36)
Accretion expense	14	9
Revisions in estimated liabilities(1)	133	13
Asset retirement obligations, end of period	347	171
Less: current portion(2)	11	5
Asset retirement obligations - long-term	$ 336	$ 166

(1) Revisions in estimated liabilities for the year ended December 31, 2022 are primarily the result of changes in estimated future plugging and abandonment costs due to inflation and other factors, as well as changes in the timing of when we expect to incur these liabilities.
(2) The current portion of the asset retirement obligation is included in other accrued liabilities in the Company's consolidated balance sheets.

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

7. EQUITY METHOD INVESTMENTS

At December 31, 2022 and 2021, the Company had the following equity method investments:

	Ownership Interest	December 31, 2022	December 31, 2021
		(In millions)	
EPIC Crude Holdings, LP	10 %	$ 101	$ 107
Gray Oak Pipeline, LLC(1)	10 %	115	121
Wink to Webster Pipeline LLC	4 %	87	86
OMOG JV LLC(2)	43 %	191	188
BANGL LLC	10 %	28	—
WTG joint venture	25 %	156	111
Sprouts Energy LLC	50 %	3	—
Total		$ 681	$ 613

(1) The Company's investment of $115 million in the Gray Oak Pipeline, LLC ("Gray Oak") was classified in assets held for sale in the consolidated balance sheet at December 31, 2022, and was subsequently divested in January 2023 as further discussed in Note 16— Subsequent Events.

(2) On November 1, 2022, in connection with a merger completed by OMOG JV LLC ("OMOG"), Rattler entered into a restated limited liability company agreement with OMOG which decreased the Company's ownership interest in OMOG from 60% to 43%.

Currently, the Company receives distributions from Gray Oak, Wink to Webster and OMOG, which are classified either within the operating or investing sections of the consolidated statements of cash flows by determining the nature of each distribution. The following table presents total distributions received from the Company's equity method investments for the periods indicated:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Gray Oak Pipeline, LLC	$ 28	$ 26	$ 23
Wink to Webster Pipeline LLC	5	—	—
OMOG JV LLC	19	18	17
Total	$ 52	$ 44	$ 40

The following summarizes the income (loss) of equity method investees for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
EPIC Crude Holdings, LP	$ (7)	$ (16)	$ (9)
Gray Oak Pipeline, LLC	22	16	10
Wink to Webster Pipeline LLC	4	(3)	(2)
OMOG JV LLC	14	12	(9)
WTG joint venture	44	6	—
Total	$ 77	$ 15	$ (10)

The Company reviews its equity method investments to determine if a loss in value which is other than temporary has occurred when events indicate the carrying value of the investment may not be recoverable. If such a loss has occurred, the Company recognizes an impairment provision. No significant impairments were recorded for the Company's equity method investments for the years ended December 31, 2022, 2021 or 2020. The Company's investees all serve customers in the oil and natural gas industry, which experienced economic challenges due to the COVID-19 pandemic and other macroeconomic factors during 2020 prior to recovering in 2021. If similar economic challenges occur in future periods, it could result in circumstances requiring the Company to record potentially material impairment charges on its equity method investments.

8. DEBT

The Company's debt consisted of the following as of the dates indicated:

	December 31, 2022	December 31, 2021
	(In millions)	
5.375% Senior Notes due 2022[(1)]	$ —	$ 25
7.320% Medium-term Notes, Series A, due 2022	—	20
5.250% Senior Notes due 2023[(1)]	10	10
2.875% Senior Notes due 2024	—	1,000
4.750% Senior Notes due 2025	—	500
3.250% Senior Notes due 2026	780	800
5.625% Senior Notes due 2026[(1)]	14	14
7.125% Medium-term Notes, Series B, due 2028	73	100
3.500% Senior Notes due 2029	1,021	1,200
3.125% Senior Notes due 2031	789	900
6.250% Senior Notes due 2033	1,100	—
4.400% Senior Notes due 2051	650	650
4.250% Senior Notes due 2052	750	—
6.250% Senior Notes due 2053	650	—
DrillCo Agreement[(2)]	—	58
Unamortized debt issuance costs	(43)	(31)
Unamortized discount costs	(26)	(28)
Unamortized premium costs	4	8
Unamortized basis adjustment of dedesignated interest rate swap agreements[(3)]	(106)	(18)
Revolving credit facility	—	—
Viper revolving credit facility	152	304
Viper 5.375% Senior Notes due 2027	430	480
Rattler revolving credit facility	—	195
Rattler 5.625% Senior Notes due 2025	—	500
Total debt, net	6,248	6,687
Less: current maturities of long-term debt	(10)	(45)
Total long-term debt	$ 6,238	$ 6,642

(1) At the effective time of the QEP Merger, QEP became a wholly owned subsidiary of the Company and remained the issuer of these senior notes.

(2) The Company entered into a participation and development agreement (the "DrillCo Agreement"), dated September 10, 2018, with Obsidian Resources, L.L.C. ("CEMOF") to fund oil and natural gas development. On December 6, 2022, the Company and CEMOF entered into a letter agreement whereby the Company paid approximately $30 million, net of customary closing adjustments, to repay the $12 million outstanding debt balance and terminate the DrillCo Agreement. The Company recorded an overall loss on extinguishment of debt of $20 million in connection with the termination of the DrillCo Agreement.

(3) Represents the unamortized basis adjustment related to two receive-fixed, pay variable interest rate swap agreements which were previously designated as fair value hedges of the Company's $1.2 billion 3.500% fixed rate senior notes due 2029. These swaps were dedesignated in the second quarter of 2022 as discussed further in Note 12—Derivatives.

Debt maturities as of December 31, 2022, excluding debt issuance costs, premiums and discounts and the unamortized basis adjustment of dedesignated interest rate swap agreements are as follows:

Year Ending December 31,		
		(In millions)
23	$	10
24		—
25		152
26		794
27		430
ereafter		5,033
tal	$	6,419

References in this section to the Company shall mean Diamondback Energy, Inc. and Diamondback E&P, collectively, unless otherwise specified.

Second Amended and Restated Credit Facility

The Company maintains a credit agreement, as amended, which provides for a maximum credit amount of $1.6 billion, which may be further increased to a total maximum commitment of $2.6 billion. As of December 31, 2022, the Company had no outstanding borrowings under the credit agreement and $3 million in outstanding letters of credit, which reduce available borrowings under the credit agreement on a dollar for dollar basis. The weighted average interest rate on borrowings under the credit agreement was 3.91%, 1.67% and 2.02% for the years ended December 31, 2022, 2021 and 2020, respectively.

On June 2, 2022, the Company entered into a thirteenth amendment to the credit agreement dated as of November 1, 2013, with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. This amendment, among other things, (i) extended the maturity date to June 2, 2027, which may be further extended by two one-year extensions pursuant to the terms set forth in the credit agreement, (ii) decreased the interest rate margin applicable to the loans and certain fees payable under the credit agreement and (iii) replaced the LIBOR interest rate benchmark with SOFR. Outstanding borrowings under the credit agreement bear interest at a per annum rate elected by Diamondback E&P 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 1.0%), in each case plus the applicable margin. After giving effect to the amendment, (i) the applicable margin ranges from 0.125% to 1.000% per annum in the case of the alternate base rate, and from 1.125% to 2.000% per annum in the case of Adjusted Term SOFR, in each case based on the pricing level, and (ii) the commitment fee ranges from 0.125% to 0.325% per annum on the average daily unused portion of the commitments, based on the pricing level. The pricing level depends on the Company’s long-term senior unsecured debt ratings. The Company applied the optional expedient in ASU 2020-04, “Reference Rate Reform (Topic 848) - Facilitation of the Effects of Reference Rate Reform on Financial Reporting” for this contract modification, which did not have an impact on its financial position, results of operations or liquidity.

The credit agreement contains a financial covenant that requires us to maintain a Total Net Debt to Capitalization Ratio (as defined in the credit agreement) of no more than 65%. As of December 31, 2022 and 2021, the Company was in compliance with all financial maintenance covenants under the revolving credit facility, as then in effect.

2022 Issuance of Notes

December 2022 Notes Offering

On December 13, 2022, Diamondback Energy, Inc. issued $650 million aggregate principal amount of 6.250% Senior Notes due March 15, 2053 (the “December 2022 Notes”) and received net proceeds of $643 million, after deducting debt issuance costs and discounts of $7 million and underwriting discounts and offering expenses. Interest on the December 2022 Notes is payable semi-annually on March 15 and September 15 of each year, beginning on March 15, 2023.

October 2022 Notes Offering

On October 28, 2022, the Company issued $1.1 billion of 6.250% Senior Notes due 2033 (the “October 2022 Notes”) and received net proceeds of $1.1 billion, after deducting debt issuance costs and discounts of $15 million and underwriting discounts and offering expense. Interest on the October 2022 Notes is payable semi-annually in March and September, beginning in March 2023.

March 2022 Notes Offering

On March 17, 2022, the Company issued $750 million aggregate principal amount of 4.250% Senior Notes due March 15, 2052 (the “March 2022 Notes”) and received net proceeds of $739 million, after deducting debt issuance costs and discounts of $11 million and underwriting discounts and offering expenses. Interest on the March 2022 Notes is payable semi-annually on March 15 and September 15 of each year, beginning on September 15, 2022.

The December 2022 Notes, the October 2022 Notes and the March 2022 Notes are the Company’s senior unsecured obligations and are fully and unconditionally guaranteed by Diamondback E&P, are senior in right of payment to any of the Company’s future subordinated indebtedness and rank equal in right of payment with all of the Company’s existing and future senior indebtedness.

2022 Retirement of Notes

In the third quarter of 2022, the Company fully redeemed the $25 million principal amount of the outstanding 5.375% Notes due 2022 and fully repaid at maturity the $20 million principal amount of the outstanding 7.320% Medium-term Notes, Series A due 2022. The Company funded these transactions with cash on hand.

Additionally, the Company used a portion of the net proceeds from the October 2022 Notes offering to fund, in full, the redemption of the $500 million principal amount of Rattler’s 5.625% Senior Notes due 2025. The redemption included a premium and accrued and unpaid interest for a total cash consideration of $522 million. These redemptions resulted in an immaterial loss on extinguishment of debt.

In the second quarter of 2022, the Company repurchased principal amounts of $27 million of its 7.125% Medium-term Notes due 2028, $111 million of its 3.125% Senior Notes due 2031, $179 million of its 3.500% Senior Notes due 2029 and $20 million of its 3.250% Senior Notes due 2026 for total cash consideration, including accrued interest of $322 million.

Additionally, during the second quarter of 2022, Viper repurchased $50 million in principal amount of its 5.375% Senior Notes due 2027 for total cash consideration of $49 million. These repurchases resulted in an immaterial loss on extinguishment of debt. The Company funded its repurchases with cash on hand and Viper funded its repurchases with cash on hand and borrowings under the Viper credit agreement.

In the first quarter of 2022, the Company fully redeemed the $500 million and $1.0 billion principal amounts of its outstanding 4.750% Senior Notes due 2025 and 2.875% Senior Notes due 2024, respectively. Cash consideration for these redemptions totaled $1.6 billion, including make-whole premiums of $47 million, which resulted in a loss on extinguishment of debt of $54 million. The Company funded the redemptions with a portion of the net proceeds from the March 2022 Notes offering and cash on hand.

2021 Issuances of Notes

On March 24, 2021, Diamondback Energy, Inc. issued $650 million aggregate principal amount of 0.900% Senior Notes due March 24, 2023 (the “2023 Notes”), $900 million aggregate principal amount of 3.125% Senior Notes due March 24, 2031 (the “2031 Notes”) and $650 million aggregate principal amount of 4.400% Senior Notes due March 24, 2051 (the “2051 Notes” and together with the 2023 Notes and the 2031 Notes, the “March 2021 Notes”) and received proceeds, net of $24 million in debt issuance costs and discounts, of $2.18 billion. The net proceeds were primarily used to fund the repurchase of other senior notes outstanding as discussed further below. Interest on the March 2021 Notes is payable semi-annually in March and September, beginning in September 2021. The Company redeemed the 2023 Notes in November 2021 as discussed in “—2021 Retirement of Notes” below.

The 2031 Notes and the 2051 Notes are the Company’s senior unsecured obligations and are fully and unconditionally guaranteed by Diamondback E&P. The 2031 Notes and the 2051 Notes are senior in right of payment to any of the Company’s future subordinated indebtedness and rank equal in right of payment with all of the Company’s existing and future senior indebtedness. The 2031 Notes and the 2051 Notes are effectively subordinated to the Company’s existing and future secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all of the existing and future indebtedness and other liabilities of the Company’s subsidiaries other than Diamondback E&P.

2021 Retirement of Notes

On November 1, 2021, the Company redeemed the aggregate $650 million principal amount of its outstanding 2023 Notes at a redemption price equal to 100% of the principal amount, plus accrued and unpaid interest up to, but not including, the redemption date. The Company funded the redemption with proceeds received from the divestiture of its Williston Basin assets and cash on hand.

In August 2021, the Company redeemed the remaining $432 million principal amount of its outstanding 5.375% Senior Notes due 2025 for total cash consideration of $449 million, including redemption and early premium fees of $12 million, which resulted in a loss on extinguishment of debt during the year ended December 31, 2022 of $12 million. The Company funded the redemption with cash on hand and borrowings under its revolving credit facility.

In June 2021, the Company redeemed the remaining $191 million principal amount of the outstanding 4.625% senior notes of Energen due on September 1, 2021. The Company recorded an immaterial pre-tax loss on extinguishment of debt related to the redemption, which included the write-off of unamortized debt discounts associated with the redeemed notes. The Company funded the redemption with internally generated cash flow from operations as well as proceeds from the divestitures of certain non-core assets as discussed in Note 4—Acquisitions and Divestitures.

On March 17, 2021, at the time of the QEP Merger discussed in Note 4—Acquisitions and Divestitures, QEP had outstanding debt at fair values consisting of $478 million of 5.375% Senior Notes due 2022 (the “QEP 2022 Notes”), $673 million of 5.250% Senior Notes due 2023 (the “QEP 2023 Notes”) and $558 million of 5.625% Senior Notes due 2026 (the “QEP 2026 Notes” and together with the QEP 2022 Notes and QEP 2023 Notes, the “QEP Notes”). Subsequent to the QEP Merger, in March 2021, the Company repurchased pursuant to tender offers commenced by the Company, approximately $1.65 billion in fair value carrying amount of the QEP Notes for total cash consideration of $1.7 billion, including redemption and early premium fees of $152 million, which resulted in a loss on extinguishment of debt during the year ended December 31, 2021 of approximately $47 million. The aggregate fair value of the QEP Notes repurchased consisted of (i) $453 million of the outstanding fair value carrying amount of the QEP 2022 Notes, (ii) $663 million, of the outstanding fair value carrying amount of the QEP 2023 Notes and (iii) $538 million, of the outstanding fair value carrying amount of the QEP 2026 Notes.

In March 2021, the Company also repurchased an aggregate of $368 million principal amount of its 5.375% Senior Notes due 2025 for total cash consideration of $381 million, including redemption and early premium fees of $13 million. This resulted in a loss on extinguishment of debt during the year ended December 31, 2021 of $14 million. The Company funded the repurchases of the QEP Notes and 5.375% Senior Notes due 2025 with the proceeds from the March 2021 Notes offering discussed above.

In connection with the tender offers to repurchase the QEP Notes discussed above, the Company also solicited consents from holders of the QEP Notes to amend the indenture for the QEP Notes to, among other things, eliminate substantially all of the restrictive covenants and related provisions and certain events of default contained in the indenture under which the QEP Notes were issued. The Company received the requisite number of consents and, on March 23, 2021, entered into a supplemental indenture relating to the QEP Notes adopting these amendments.

Viper’s Credit Agreement

Viper LLC maintains a credit agreement, as amended, which provides for a maximum credit amount of $2.0 billion and a borrowing base of $580 million. As of December 31, 2022, Viper LLC had elected a commitment amount of $500 million, with $152 million of outstanding borrowings and $348 million available for future borrowings under the Viper credit agreement. The weighted average interest rates on borrowings under the Viper credit agreement were 4.22%, 2.35%, and 2.20% for the years ended December 31, 2022, 2021 and 2020, respectively.

On November 18, 2022, Viper LLC entered into the ninth amendment to the existing credit agreement, which (i) maintained the maximum amount of the revolving credit facility at $2.0 billion, (ii) reaffirmed the borrowing base of $580 million based on Viper LLC’s oil and natural gas reserves and other factors, (iii) maintained Viper LLC’s ability to elect a commitment amount that is less than its borrowing base as determined by the lenders and (iv) replaced the LIBOR interest rate benchmark with SOFR.

The outstanding borrowings under the Viper credit agreement bear interest at a rate elected by Viper LLC 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 1.0%), 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. Viper LLC 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 agreement is secured by substantially all the assets of Viper and Viper LLC.

The Viper credit agreement 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 Viper credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the Viper credit agreement	Not less than 1.0 to 1.0
Ratio of secured debt to EBITDAX, as defined in the Viper credit agreement	Not greater than 2.5 to 1.0

As of December 31, 2022, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement.

Rattler's Credit Agreement

In connection with the Rattler Merger in August 2022, all outstanding borrowings under Rattler LLC's credit agreement in the amount of $269 million were fully repaid, all liens granted to secure such obligations were released and Rattler LLC's credit agreement was terminated.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2022, 2021 and 2020:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Interest expense	$ 272	$ 277	$ 250
Other fees and expenses	12	11	6
Less: interest income	1	1	4
Less: capitalized interest	124	88	55
Interest expense, net	$ 159	$ 199	$ 197

9. STOCKHOLDERS' EQUITY AND EARNINGS PER SHARE

Stock Repurchase Programs

In May 2019, the Company's board of directors approved a stock repurchase program to acquire up to $2.0 billion of the Company's outstanding common stock through December 31, 2020. This repurchase program was suspended in the first quarter of 2020. In September 2021, the Company's board of directors approved a new stock repurchase program to acquire up to $2 billion of the Company's outstanding common stock, and on July 28, 2022, the Company's board of directors approved an increase in the Company's common stock repurchase program from $2.0 billion to $4.0 billion. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. During the years ended December 31, 2022, 2021 and 2020, the Company repurchased approximately $1.1 billion, $431 million and $98 million, respectively, of common stock under the respective repurchase programs. As of December 31, 2022, $2.5 billion remained available for use to repurchase shares under the Company's common stock repurchase program.

Change in Ownership of Consolidated Subsidiaries

Non-controlling interests in the accompanying consolidated financial statements represent minority interest ownership in Viper and Rattler through the Effective Date of the Rattler Merger and are presented as a component of equity. The Company's ownership percentage in Viper and Rattler have historically changed as a result of public offerings, issuance of units for acquisitions, issuance of unit-based compensation, repurchases of common units and distribution equivalent rights paid on their units. These changes in ownership percentage and the disproportionate allocation of net income to the Company result in a difference between the Company's share of the underlying net book value in Viper and Rattler, prior to the Effective Date of the Rattler Merger. When the Company's relative ownership interests change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, occur.

The following table summarizes changes in the ownership interest in consolidated subsidiaries during the respective periods:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Net income (loss) attributable to the Company	$ 4,386	$ 2,182	$ (4,517)
Change in ownership of consolidated subsidiaries[1]	(46)	66	358
Change from net income (loss) attributable to the Company's stockholders and transfers to non-controlling interest	$ 4,340	$ 2,248	$ (4,159)

(1) The year ended December 31, 2020 includes an adjustment to non-controlling interest for Rattler of $329 million and to additional paid-in-capital of $329 million to reflect the ownership structure that was effective at June 30, 2020. The adjustment had no impact on the consolidated statement of income or consolidated statement of cash flows for the year ended December 31, 2020.

Viper's Common Unit Repurchase Program

The board of directors of Viper's General Partner approved a common unit repurchase program to acquire up to $750 million of Viper's outstanding common units over an indefinite period of time. During the years ended December 31, 2022, 2021 and 2020, Viper repurchased approximately $151 million, $46 million, and $24 million of its common units under its repurchase program. As of December 31, 2022, $529 million remained available for use to repurchase common units under Viper's common unit repurchase program.

Distributions to Non-Controlling Interest

During the years ended December 31, 2022, 2021 and 2020 Viper made $182 million, $76 million, and $46 million of distributions to its common unitholders, respectively, and prior to the Rattler Merger, Rattler made $35 million, $36 million and $47 million of distributions to its common unitholders, respectively, in accordance with the distribution policies approved by their respective boards of directors. These distributions are reflected under the caption "Distributions to non-controlling interest" on the Company's consolidated statement of stockholders' equity and consolidated statements of cash flows.

Earnings (Loss) Per Share

The Company's basic earnings (loss) per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, the per share earnings of Viper are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiaries.

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

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts)		
Net income (loss) attributable to common stock	$ 4,386	$ 2,182	$ (4,517)
Less: distributed and undistributed earnings allocated to participating securities[1]	(42)	(20)	(2)
Net income (loss) attributable to common stockholders	$ 4,344	$ 2,162	$ (4,519)
Weighted average common shares outstanding:			
Basic weighted average common shares outstanding	176,539	176,643	157,976
Effect of dilutive securities:			
Weighted-average potential common shares issuable	—	—	—
Diluted weighted average common shares outstanding	176,539	176,643	157,976
Basic net income (loss) attributable to common stock	$ 24.61	$ 12.24	$ (28.61)
Diluted net income (loss) attributable to common stock	$ 24.61	$ 12.24	$ (28.61)

(1) Unvested restricted stock awards and performance stock awards that contain non-forfeitable distribution equivalent rights are considered participating securities and therefore are included in the earnings per share calculation pursuant to the two-class method.

10. EQUITY-BASED COMPENSATION

On June 3, 2021, the Company's stockholders approved and adopted the Company's 2021 amended and restated equity incentive plan (the "Equity Plan"), which, among other things, increased total shares authorized for issuance from 8.3 million to 11.8 million. At December 31, 2022, the Company had 5.7 million shares of common stock available for future grants.

Under the Equity Plan, approved by the board of directors, the Company is authorized to issue incentive and non-statutory stock options, restricted stock awards and restricted stock units, performance awards and stock appreciation rights to eligible employees. At December 31, 2022, the Company had outstanding restricted stock units and performance-based restricted stock units under the Equity Plan. The Company also has immaterial amounts of restricted share awards and stock appreciation rights outstanding which were issued under plans assumed in connection with previously completed mergers. The Company classifies all of its awards, other than its stock appreciation rights, as equity-based awards and estimates the fair values of restricted stock awards and units as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable vesting period. Stock appreciation rights are considered liability-classified awards.

In addition to the Equity Plan, Viper maintains its own long-term incentive plan, which is not significant to the Company.

The following table presents the effects of equity and stock based compensation plans and related costs on the Company's financial statements:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
General and administrative expenses	$ 55	$ 51	$ 37
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 21	$ 20	$ 16

Restricted Stock Units

The Company estimates the fair values of restricted stock awards and units as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable vesting period.

The following table presents the Company's restricted stock unit activity under the Equity Plan during the year ended December 31, 2022:

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2021	1,079,589	$ 62.09
Granted[(1)]	512,311	$ 133.12
Vested	(592,917)	$ 69.39
Forfeited	(80,081)	$ 76.31
Unvested at December 31, 2022	918,902	$ 95.74

(1) Includes 156,490 restricted stock units granted through the conversion of Rattler restricted stock units at the completion of the Rattler Merger.

The aggregate grant date fair value of restricted stock units that vested during the years ended December 31, 2022, 2021 and 2020 was $41 million, $46 million and $25 million, respectively. As of December 31, 2022, the Company's unrecognized compensation cost related to unvested restricted stock units was $69 million and is expected to be recognized over a weighted-average period of 1.7 years.

Performance-Based Restricted Stock Units

To provide long-term incentives for executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance-based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period.

In March 2020, eligible employees received performance restricted stock unit awards totaling 225,047 units from which a minimum of 0% and a maximum of 200% units could be awarded based upon the TSR during the three-year performance period of January 1, 2020 to December 31, 2022 and cliff vest at December 31, 2022 subject to continued employment. The initial payout of the March 2020 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%.

In March 2021, eligible employees received performance restricted stock unit awards totaling 198,454 units from which a minimum of 0% and a maximum of 200% of the units could be awarded based upon the measurement of total stockholder return of the Company's common stock as compared to a designated peer group during the 3-year performance period of January 1, 2021 to December 31, 2023 and cliff vest at December 31, 2023 subject to continued employment. The initial payout of the March 2021 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%.

In March 2022, eligible employees received performance restricted stock unit awards totaling 126,905 units from which a minimum of 0% and a maximum of 200% of the units could be awarded based upon the measurement of total stockholder return of the Company's common stock as compared to a designated peer group during the 3-year performance period of January 1, 2022 to December 31, 2024 and cliff vest at December 31, 2024 subject to continued employment. The initial payout of the March 2022 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period.

The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions for the awards granted during the period presented:

	2022	2021	2020
Grant-date fair value	$ 237.13	$ 131.06	$ 70.17
Grant-date fair value (5-year vesting)			$ 132.48
Risk-free rate	1.44 %	15.00 %	86.00 %
Company volatility	72.10 %	69.60 %	36.70 %

The following table presents the Company's performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2022:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2021	456,459	$ 100.17
Granted	126,905	$ 237.13
Vested	(225,047)	$ 68.19
Forfeited	(10,436)	$ 177.96
Unvested at December 31, 2022(1)	347,881	$ 168.48

(1) A maximum of 811,264 units could be awarded based upon the Company's final TSR ranking.

As of December 31, 2022, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $32 million, which is expected to be recognized over a weighted-average period of 1.8 years.

11. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The Company is subject to corporate income taxes and the Texas margin tax. The Company and its subsidiaries, other than Viper, Viper LLC, and Rattler LLC, file a federal corporate income tax return on a consolidated basis. As discussed further below, Viper became a taxable entity for federal income tax purposes effective May 10, 2018, and as such files a federal corporate income tax return including the activity of its investment in Viper LLC. Viper's provision for income taxes is included in the Company's consolidated income tax provision and, to the extent applicable, in net income attributable to the non-controlling interest.

For periods subsequent to the Effective Date of the Rattler Merger, Rattler is anticipated to be a member of the group filing consolidated income tax returns with Diamondback Energy, Inc. and its subsidiaries. As such, Rattler's current and deferred income taxes continue to be included in the Company's consolidated income tax expense from continuing operations and, only for periods prior to the Rattler Merger, in net income attributable to the non-controlling interest.

The Company's effective income tax rates were 20.5%, 21.7% and 19.1% for the years ended December 31, 2022, 2021 and 2020, respectively. Total income tax expense for the year ended December 31, 2022 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to (i) state income taxes, net of federal benefit, and (ii) the impact of permanent differences between book and taxable income, partially offset by (iii) tax benefit resulting from a partial reduction in the valuation allowance on Viper's and QEP's deferred tax assets for the year ended December 31, 2022. Total income tax benefit for the year ended December 31, 2021 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to state income taxes, net of federal benefit. Total income tax expense for the year ended December 31, 2020 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax loss for the period primarily due to the impact of recording a valuation allowance on Viper's deferred tax assets, partially offset by state income taxes net of federal benefit and by tax benefit resulting from the carryback of federal net operating losses.

The CHIPS and Science Act of 2022 was enacted on August 9, 2022, and the IRA was enacted on August 16, 2022, which imposes a 15% corporate alternative minimum tax ("CAMT") on the "adjusted financial statement income" of certain large corporations (generally, corporations reporting at least $1 billion of average adjusted pre-tax net income on their consolidated financial statements) as well as an excise tax of 1% on the fair market value of certain public company stock/

unit repurchases for tax years beginning after December 31, 2022, and included several other provisions applicable to U.S. income taxes for corporations. The Company considered the impact of this legislation in the period of enactment and concluded there was not a material impact to the Company's current or deferred income tax balances. The Company has made an accounting policy election to account for the effects of the CAMT on realizability of its deferred tax assets as a period cost, to the extent the Company is subject to the CAMT and related tax consequences arise in future periods. These changes are effective for the 2023 tax periods.

The components of the Company's consolidated provision for income taxes from continuing operations for the years ended December 31, 2022, 2021 and 2020 are as follows:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Current income tax provision (benefit):			
Federal	$ 421	$ 10	$ (62)
State	33	15	—
Total current income tax provision (benefit)	454	25	(62)
Deferred income tax provision (benefit):			
Federal	706	594	(1,010)
State	14	12	(32)
Total deferred income tax provision (benefit)	720	606	(1,042)
Total provision for (benefit from) income taxes	$ 1,174	$ 631	$ (1,104)

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

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Income tax expense (benefit) at the federal statutory rate (21%)	$ 1,205	$ 610	$ (1,213)
Income tax benefit relating to net operating loss carryback	—	—	(25)
State income tax expense, net of federal tax effect	42	23	(30)
Non-deductible compensation	10	10	6
Change in valuation allowance	(71)	(12)	153
Other, net	(12)	—	5
Provision for (benefit from) income taxes	$ 1,174	$ 631	$ (1,104)

The components of the Company's deferred tax assets and liabilities as of December 31, 2022 and 2021 are as follows:

	December 31, 2022	December 31, 2021
	(In millions)	
Deferred tax assets:		
Net operating loss and other carryforwards	$ 406	$ 682
Derivative instruments	—	36
Stock based compensation	5	5
Viper's investment in Viper LLC	148	163
Rattler's investment in Rattler LLC	1	40
Other	16	22
Deferred tax assets	576	948
Valuation allowance	(223)	(315)
Deferred tax assets, net of valuation allowance	353	633
Deferred tax liabilities:		
Oil and natural gas properties and equipment	2,109	1,702
Midstream investments	235	224
Derivative instruments	12	—
Other	2	5
Total deferred tax liabilities	2,358	1,931
Net deferred tax liabilities	$ 2,005	$ 1,298

The Company had net deferred tax liabilities of approximately $2.0 billion and $1.3 billion at December 31, 2022 and 2021, respectively.

At December 31, 2022, the Company had approximately $457 million of federal NOLs and $4 million of federal tax credits expiring in 2037 and $887 million of federal NOLs with an indefinite carryforward life, including NOLs acquired from QEP and from Rattler. The Company principally operates in the state of Texas and is subject to Texas Margin Tax, which currently does not include an NOL carryover provision. The Company's federal tax attributes, including those acquired from QEP and Rattler, are subject to an annual limitation under Section 382 of the Internal Revenue Code of 1986, as amended, which relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three-year look back period. Other than as described below regarding realization of tax attributes acquired from QEP, the Company believes that the application of Section 382 will not have an adverse effect on future usage of the Company's NOLs and credits.

On August 24, 2022, the Company completed the Rattler Merger. Management considered the likelihood that the federal net operating losses and other tax attributes acquired from Rattler will be utilized, including in light of Rattler's inclusion in consolidated income tax returns with Diamondback for periods subsequent to the Rattler Merger, and in light of the annual limitation on utilization of tax attributes following Rattler's ownership change pursuant to Internal Revenue Code Section 382. As a result of the assessment, including consideration of all available positive and negative evidence, management determined that it continues to be more likely than not that Rattler will realize its deferred tax assets as of December 31, 2022.

On March 17, 2021, the Company completed its acquisition of QEP. For federal income tax purposes, the transaction qualified as a nontaxable merger whereby the Company acquired carryover tax basis in QEP's assets and liabilities. The Company's opening balance sheet net deferred tax asset was finalized during the first quarter of 2022 at $39 million, and primarily consisted of deferred tax assets related to tax attributes acquired from QEP, partially offset by a valuation allowance related to federal and state tax attributes estimated not more likely than to be realized prior to expiration and deferred tax liabilities resulting from the excess of financial reporting carrying value over tax basis of oil and natural gas properties and other assets acquired from QEP.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)

As of December 31, 2022, the Company had a valuation allowance of $11 million related to federal NOL and credit carryforwards acquired from QEP which are estimated not more likely than not to be realized prior to expiration. In addition, the Company had a valuation allowance of $113 million primarily related to certain state NOL carryforwards which the Company does not believe are realizable as it does not anticipate future operations in those states and a valuation allowance of $98 million related to Viper's deferred tax assets, as discussed further below. Management's assessment at each balance sheet date included consideration of all available positive and negative evidence including the anticipated timing of reversal of deferred tax liabilities and the limitations imposed by Internal Revenue Code Section 382 on certain of the Company's NOLs and other carryforwards. Management believes that the balance of the Company's NOLs are realizable to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. As of December 31, 2022, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

At December 31, 2022, the Company's net deferred tax liabilities include deferred tax assets of approximately $148 million related to Viper's investment in Viper LLC. Deferred taxes are provided on the difference between Viper's basis for financial accounting purposes and basis for federal income tax purposes in its investment in Viper LLC.

As of December 31, 2022, Viper had a valuation allowance of approximately $98 million related to deferred tax assets that Viper does not believe are more likely than not to be realized. During the year ended December 31, 2022, Viper recognized deferred income tax benefit of $50 million 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. Management's assessment of all available evidence, both positive and negative, supporting realizability of Viper's deferred tax assets as required by applicable accounting standards, resulted in recognition of tax benefit for the portion of Viper's deferred tax assets considered more likely than not to be realized. The positive evidence assessed included recent cumulative income due in part to higher commodity prices and an expectation of future taxable income based upon recent actual and forecasted production volumes and prices. Viper retained a partial valuation allowance on its deferred tax assets due in part to potential future volatility in commodity prices impacting the likelihood of future realizability. At December 31, 2021, Viper had a full valuation allowance against its deferred tax assets, based on its assessment of all available evidence, both positive and negative, supporting realizability of its deferred tax assets.

The following table sets forth changes in the Company's unrecognized tax benefits:

	December 31,	
	2022	2021
	(In millions)	
Balance at beginning of year	$ 7	$ 7
Increase resulting from prior period tax positions	—	—
Increase resulting from current period tax positions	—	—
Balance at end of year	7	7
Less: Effects of temporary items	(4)	(4)
Total that, if recognized, would impact the effective income tax rate as of the end of the year	$ 3	$ 3

The Company recognizes the tax benefit from a tax position only if it is more likely than not that it will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. The Company's federal and state income tax returns for 2012 through the current tax year remain open and subject to examination by the IRS and major state taxing jurisdictions. It is reasonably possible that significant changes to the reserve for uncertain tax positions may occur as a result of various audits and the expiration of the statute of limitations. Although the timing and outcome of tax examinations is highly uncertain, the Company does not expect the change in unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2022 and 2021, there was an insignificant amount of interest and no penalties related to each period associated with uncertain tax positions recognized in the Company's consolidated financial statements.

12. DERIVATIVES

At December 31, 2022, the Company has commodity derivative contracts and interest rate swaps outstanding. All derivative financial instruments are recorded at fair value.

Commodity Contracts

The Company has entered into multiple crude oil, natural gas and natural gas liquids derivatives, indexed to the respective indices as noted in the table below, to reduce price volatility associated with certain of its oil and natural gas sales. The Company has not designated its commodity derivative instruments as hedges for accounting purposes and, as a result, marks its commodity derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

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 participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company has entered into commodity derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk. As such, the Company does not require collateral from its counterparties.

The Company had multiple commodity derivative contracts that contained an other-than-insignificant financing element at inception during 2021 and, therefore, the cash receipts were classified as cash flows from financing activities in the consolidated statements of cash flow for the year ended December 31, 2021.

As of December 31, 2022, the Company had the following outstanding commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed:

					Swaps		Collars	
Settlement Month	Settlement Year	Type of Contract	Bbls/MMBtu Per Day	Index	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
OIL								
Jan. - June	2023	Costless Collar	6,000	Brent	$—	$—	$60.00	$114.57
Jan. - Dec.	2023	Basis Swap(1)	24,000	Argus WTI Midland	$0.90	$—	$—	$—
NATURAL GAS								
Jan. - Mar.	2023	Costless Collar	370,000	Henry Hub	$—	$—	$3.14	$9.28
Apr. - June	2023	Costless Collar	330,000	Henry Hub	$—	$—	$3.17	$9.13
July - Dec.	2023	Costless Collar	310,000	Henry Hub	$—	$—	$3.18	$9.22
Jan. - Dec.	2024	Costless Collar	200,000	Henry Hub	$—	$—	$3.00	$8.42
Jan. - June	2023	Basis Swap(1)	350,000	Waha Hub	$(1.20)	$—	$—	$—
July - Dec.	2023	Basis Swap(1)	330,000	Waha Hub	$(1.24)	$—	$—	$—
Jan. - Dec.	2024	Basis Swap(1)	330,000	Waha Hub	$(1.17)	$—	$—	$—

(1) The Company has fixed price basis swaps for the spread between the Cushing crude oil price and the Midland WTI crude oil price as well as the spread between the Henry Hub natural gas price and the Waha Hub natural gas price. The weighted average differential represents the amount of reduction to the Cushing, Oklahoma, oil price and the Waha Hub natural gas price for the notional volumes covered by the basis swap contracts.

Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Strike Price	Deferred Premium
OIL						
Jan. - Mar.	2023	Put	90,000	Brent	$53.72	$1.76
Jan. - Mar.	2023	Put	32,000	Argus WTI Houston	$54.06	$1.77
Jan. - Mar.	2023	Put	12,000	WTI	$54.50	$1.82
Apr. - June	2023	Put	64,000	Brent	$53.52	$1.81
Apr. - June	2023	Put	18,000	Argus WTI Houston	$53.33	$1.75
Apr. - June	2023	Put	8,000	WTI	$55.00	$1.79
July - Sep.	2023	Put	32,000	Brent	$53.91	$1.85
July - Sep.	2023	Put	4,000	Argus WTI Houston	$55.00	$1.84
Oct. - Dec.	2023	Put	5,000	Brent	$55.00	$1.87

Interest Rate Swaps

In the second quarter of 2021, the Company entered into two interest rate swap agreements for notional amounts of $600 million, which were designated as fair value hedges of the Company’s $1.2 billion 3.50% fixed rate senior notes due 2029 (the “2029 Notes”) at inception. The Company receives a fixed 3.50% rate of interest on these swaps and pays an average variable rate of interest based on three month LIBOR plus 2.1865%, thereby limiting its exposure to changes in the fair value of debt due to movements in LIBOR interest rates. Under hedge accounting, these interest rate swaps were considered perfectly effective and gains and losses due to changes in the fair value of the interest rate swaps were completely offset by changes in the fair value of the hedged portion of the 2029 Notes in the consolidated statements of operations.

In the second quarter of 2022, the Company elected to fully dedesignate these interest rate swaps and discontinue hedge accounting. The cumulative fair value basis adjustment recorded on the 2029 Notes at the time of dedesignation totaled $135 million. This basis adjustment is being amortized to interest expense over the remaining term of the 2029 Notes utilizing the effective interest method. The dedesignated interest rate swaps are considered economic hedges of the Company’s fixed-rate debt. As such, changes in the fair value of the interest rate swaps after the date of dedesignation have been recorded in earnings under the caption “Gain (loss) on derivative instruments, net” in the consolidated statements of operations.

During 2020 and the first quarter of 2021, the Company used interest rate swaps to reduce its exposure to variable rate interest payments associated with the Company’s revolving credit facility. These interest rate swaps were not designated as hedging instruments and as a result, the Company recognized all changes in fair value immediately in earnings. During the first quarter of 2021, the Company terminated all of its previously outstanding interest rate swaps which resulted in cash received upon settlement of $80 million, net of fees, during the year ended December 31, 2021. The interest rate swaps contained an other-than-insignificant financing element at inception, and therefore, the cash receipts were classified as cash flows from financing activities in the consolidated statements of cash flow for the year ended December 31, 2021.

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 13—Fair Value Measurements for further details.

Gains and Losses on Derivative Instruments

The following table summarizes the gains and losses on derivative instruments not designated as hedging instruments included in the consolidated statements of operations:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Gain (loss) on derivative instruments, net:			
Commodity contracts	$ (528)	$ (978)	$ (32)
Interest rate swaps	(58)	130	(49)
Total	$ (586)	$ (848)	$ (81)
Net cash received (paid) on settlements:			
Commodity contracts[1][2]	$ (849)	$ (1,305)	$ 250
Interest rate swaps[3]	(1)	80	—
Total	$ (850)	$ (1,225)	$ 250

(1) The year ended December 31, 2022 includes cash paid on commodity contracts terminated prior to their contractual maturity of $138 million.
(2) The years ended December 31, 2021 and 2020 include cash paid on commodity contracts terminated prior to their contractual maturity of $16 million and cash received of $17 million, respectively.
(3) The year ended December 31, 2021 includes cash received on interest rate swap contracts terminated prior to their contractual maturity of $80 million.

13. 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.

See Note 4—Acquisitions and Divestitures for discussion of the fair values of proved oil and natural gas properties assumed in business combinations.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company’s commodity derivative instruments and interest rate swaps. The fair values of the Company’s commodity 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 fair values of the Company’s interest rate swaps previously designated as fair value hedges and those that are not designated as hedges are determined based on inputs that are readily available in public markets, are determined based on inputs readily available in public markets, can be derived from information available in publicly quote markets, or are provided by financial institutions that trade these contracts. These valuations are Level 2 inputs. The fair value of interest rate swaps is recorded as an asset or liability on the consolidated balance sheets. At December 31, 2021, the net fair value of the Company’s interest rate swaps previously designated as hedges was offset by the change in value of the hedged item, long-term debt, within the consolidated balance sheet.

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 under the captions “Derivative instruments” in the Company’s consolidated balance sheets as of December 31, 2022 and December 31, 2021. The net amounts of derivative instruments are classified as current or noncurrent based on their anticipated settlement dates.

	As of December 31, 2022					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(In millions)					
Assets:						
Current assets- Derivative instruments:						
Commodity derivative instruments	$ —	$ 197	$ —	$ 197	$ (65)	$ 132
Non-current assets- Derivative instruments:						
Commodity derivative instruments	$ —	$ 62	$ —	$ 62	$ (39)	$ 23
Liabilities:						
Current liabilities- Derivative instruments:						
Commodity derivative instruments	$ —	$ 67	$ —	$ 67	$ (65)	$ 2
Interest rate swaps	$ —	$ 45	$ —	$ 45	$ —	$ 45
Non-current liabilities- Derivative instruments:						
Commodity derivative instruments	$ —	$ 39	$ —	$ 39	$ (39)	$ —
Interest rate swaps	$ —	$ 148	$ —	$ 148	$ —	$ 148

	As of December 31, 2021					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(In millions)					
Assets:						
Current assets- Derivative instruments:						
Commodity derivative instruments	$ —	$ 60	$ —	$ 60	$ (57)	$ 3
Interest rate swaps designated as hedges	$ —	$ 10	$ —	$ 10	$ —	$ 10
Non-current assets- Derivative instruments:						
Commodity derivative instruments	$ —	$ 12	$ —	$ 12	$ (8)	$ 4
Interest rate swaps designated as hedges	$ —	$ 1	$ —	$ 1	$ (1)	$ —
Liabilities:						
Current liabilities- Derivative instruments:						
Commodity derivative instruments	$ —	$ 231	$ —	$ 231	$ (57)	$ 174
Non-current liabilities- Derivative instruments:						
Commodity derivative instruments	$ —	$ 9	$ —	$ 9	$ (8)	$ 1
Interest rate swaps designated as hedges	$ —	$ 29	$ —	$ 29	$ (1)	$ 28

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, 2022		December 31, 2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt	$ 6,248	$ 5,754	$ 6,687	$ 7,148

The fair values of the Company's credit agreement, the Viper credit agreement and prior to the Rattler Merger, the Rattler credit agreement approximate their carrying values 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 values of the outstanding notes were determined using the December 31, 2022 quoted market prices, 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 those acquired in a business combination, inventory, proved and unproved oil and gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale. Refer to Note 4—Acquisitions and Divestitures and Note 5—Property and Equipment for additional discussion of nonrecurring fair value adjustments.

Fair Value of Financial Assets

The carrying amount of cash and cash equivalents, receivables, funds held in escrow, prepaid expenses and other current assets, payables and other accrued liabilities approximate their fair value because of the short-term nature of the instruments.

14. SUPPLEMENTAL INFORMATION TO STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 135	$ 194	$ 221
Cash paid (received) for income taxes	$ 718	$ (138)	$ —
Supplemental disclosure of non-cash transactions:			
Accrued capital expenditures included in accounts payable and accrued expenses	$ 520	$ 287	$ 213
Capitalized stock-based compensation	$ 21	$ 20	$ 16
Common stock issued for acquisitions	$ 1,220	$ 1,727	$ —
Asset retirement obligations acquired	$ 19	$ 65	$ 2

15. COMMITMENTS AND CONTINGENCIES

The Company is a party to various routine legal proceedings, disputes and claims arising in the ordinary course of its business, including those that arise from interpretation of federal and state laws and regulations affecting the crude oil and natural gas industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of the Company's current operations. While the ultimate outcome of the 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.

Commitments

The following is a schedule of minimum future payments with commitments that have initial or remaining noncancellable terms in excess of one year as of December 31, 2022:

Year Ending December 31,	Transportation Commitments(1)	Electrical Fracturing Fleet(2)	Sand Supply Agreement(3)	Produced Water Disposal Commitments(4)
	(In millions)			
2023	$ 87	$ 45	$ 23	$ 5
2024	96	50	23	5
2025	101	40	22	5
2026	107	5	18	4
2027	86	—	5	4
Thereafter	379	—	—	24
Total	$ 856	$ 140	$ 91	$ 47

(1) The Company has committed to transport gross quantities of crude oil and natural gas on various pipelines under a variety of contracts including throughput and take-or-pay agreements. The Company's failure to purchase the minimum level of quantities would require it to pay shortfall fees up to the amount of the original monthly commitment amounts included in the table above.

(2) In 2022, the Company entered into three year commitments for the Company's electric fracturing fleet and related power generating services.

(3) The Company has committed to purchase minimum quantities of sand for use in its drilling operations. Our failure to purchase the minimum level of quantities would require us to pay shortfall fees up to the commitment amounts included in the table above.
(4) In 2021, the Company entered into a minimum volume commitment to purchase produced water disposal services under a 14 year agreement.

At December 31, 2022, the Company's delivery commitments covered the following gross volumes of oil:

Year Ending December 31,	Oil Volume Commitments (Bbl/d)
2023	175
2024	175
2025	175
2026	150
2027	150
Thereafter	50
Total	875

Environmental Matters

The United States Department of the Interior, Bureau of Safety and Environmental Enforcement, ordered several oil and gas operators, including a corporate predecessor of Energen Corporation, to perform decommissioning and reclamation activities related to a Louisiana offshore oil and gas production platform and related facilities. In response to the insolvency of the operator of record, the government ordered the former operators and/or alleged former lease record title owners to decommission the platform and related facilities. The Company has agreed to an arrangement with other operators to contribute to a trust to fund the decommissioning costs, however, the Company's portion of such costs are not expected to be material.

Beginning in 2013 and continuing through 2022, several coastal Louisiana parishes and the State of Louisiana have filed 43 lawsuits under Louisiana's State and Local Coastal Resources Management Act ("SLCRMA") against numerous oil and gas producers seeking damages for coastal erosion in or near oil fields located within Louisiana's coastal zone. The Company is a defendant in three of these cases, and Plaintiffs' claims against the Company relate to the prior operations of entities previously acquired by Energen Corporation. The Company has exercised contractual indemnification rights where applicable. Plaintiffs' SLCRMA theories are unprecedented, and there remains significant uncertainty about the claims (both as to scope and damages). Although we cannot predict the ultimate outcome of these matters, the Company believes the claims lack merit and intends to continue vigorously defending these lawsuits.

16. SUBSEQUENT EVENTS

Fourth Quarter 2022 Dividend Declaration

On February 16, 2023, the Company's board of directors approved an increase to the Company's annual base dividend to $3.20 per share and declared a cash dividend for the fourth quarter of 2022 of $2.95 per share of common stock, payable on March 10, 2023 to its stockholders of record at the close of business on March 3, 2023. The dividend consists of a base quarterly dividend of $0.80 per share of common stock and a variable quarterly dividend of $2.15 per share of common stock. Future base and variable dividends are at the discretion of the board of directors of the Company.

Acquisition

On January 31, 2023, the Company closed on its acquisition of all leasehold interests and related assets of Lario Permian, LLC, a wholly owned subsidiary of Lario Oil and Gas Company, and certain associated sellers (collectively "Lario"). The acquisition included approximately 25,000 gross (15,000 net) acres in the Midland Basin and certain related oil and gas assets (the "Lario Acquisition"), in exchange for 4.33 million shares of the Company's common stock and $814 million in cash, including certain customary closing adjustments. The cash portion of the consideration for the Lario Acquisition was funded through a combination of cash on hand and borrowings under our revolving credit facility. Following the closing of the Lario Acquisition, the Company filed with the SEC a shelf registration statement, which became immediately effective upon filing, registering for resale the shares of common stock issued in the Lario Acquisition, as required by the terms of the related registration rights agreement. The Lario Acquisition will be accounted for as a business combination with the fair value of consideration allocated to the acquisition date fair value of assets acquired and liabilities assumed. The Company is currently in the process of finalizing the initial accounting for this transaction and preliminary fair value measurements will be made in the Company's interim condensed consolidated financial statements for the three months ended March 31, 2023.

Divestitures

On January 9, 2023, the Company divested its 10% non-operating equity investment in Gray Oak for $172 million in cash proceeds and recorded a gain on the sale of equity method investments of approximately $53 million in the first quarter of 2023. The Company had recorded the carrying value of its Gray Oak investment in assets held for sale at December 31, 2022 as discussed further in Note 7—Equity Method Investments.

In February 2023, the Company entered into definitive agreements with unrelated third-party buyers to divest non-core assets consisting of approximately 19,000 net acres in Glasscock County and approximately 4,900 net acres in Ward and Winkler counties for combined total consideration of $439 million, subject to certain closing adjustments. The assets being sold in these pending transactions include approximately 2 MBO/d (7 MBOE/d) of 2023 production. Both of these transactions are expected to close in the second quarter of 2023, subject to completion of diligence and satisfaction of customary closing conditions.

17. SEGMENT INFORMATION

The Company reports its operations in one reportable segment: the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas. Other operations are included in the "All Other" category in the table below. The segments comprise the structure used by its Chief Operating Decision Maker ("CODM") to make key operating decisions and assess performance.

The following tables summarize the results of the Company's operating segments during the periods presented:

	Upstream	All Other	Eliminations	Total
	(In millions)			
Year Ended December 31, 2022:				
Third-party revenues	$ 9,572	$ 71	$ —	$ 9,643
Intersegment revenues	—	369	(369)	—
Total revenues	$ 9,572	$ 440	$ (369)	$ 9,643
Depreciation, depletion, amortization and accretion	$ 1,279	$ 65	$ —	$ 1,344
Income (loss) from operations	$ 6,432	$ 166	$ (90)	$ 6,508
Interest expense, net	$ (130)	$ (29)	$ —	$ (159)
Other income (expense)	$ (653)	$ 56	$ (16)	$ (613)
Provision for (benefit from) income taxes	$ 1,165	$ 9	$ —	$ 1,174
Net income (loss) attributable to non-controlling interest	$ 150	$ 26	$ —	$ 176
Net income (loss) attributable to Diamondback Energy, Inc.	$ 4,334	$ 158	$ (106)	$ 4,386
Total assets	$ 24,452	$ 2,213	$ (456)	$ 26,209

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)

	Upstream	All Other	Eliminations	Total
		(In millions)		
Year Ended December 31, 2021:				
Third-party revenues	$ 6,747	$ 50	$ —	$ 6,797
Intersegment revenues	—	371	(371)	—
Total revenues	$ 6,747	$ 421	$ (371)	$ 6,797
Depreciation, depletion, amortization and accretion	$ 1,219	$ 56	$ —	$ 1,275
Income (loss) from operations	$ 3,879	$ 180	$ (58)	$ 4,001
Interest expense, net	$ (167)	$ (32)	$ —	$ (199)
Other income (expense)	$ (925)	$ 38	$ (8)	$ (895)
Provision for (benefit from) income taxes	$ 620	$ 11	$ —	$ 631
Net income (loss) attributable to non-controlling interest	$ 57	$ 37	$ —	$ 94
Net income (loss) attributable to Diamondback Energy, Inc.	$ 2,110	$ 138	$ (66)	$ 2,182
Total assets	$ 21,329	$ 1,942	$ (373)	$ 22,898

	Upstream	All Other	Eliminations	Total
		(In millions)		
Year Ended December 31, 2020:				
Third-party revenues	$ 2,756	$ 57	$ —	$ 2,813
Intersegment revenues	—	367	(367)	—
Total revenues	$ 2,756	$ 424	$ (367)	$ 2,813
Depreciation, depletion, amortization and accretion	$ 1,257	$ 54	$ —	$ 1,311
Impairment of oil and natural gas properties	$ 6,021	$ —	$ —	$ 6,021
Income (loss) from operations	$ (5,562)	$ 182	$ (96)	$ (5,476)
Interest expense, net	$ (180)	$ (17)	$ —	$ (197)
Other income (expense)	$ (87)	$ (10)	$ (6)	$ (103)
Provision for (benefit from) income taxes	$ (1,114)	$ 10	$ —	$ (1,104)
Net income (loss) attributable to non-controlling interest	$ (190)	$ 35	$ —	$ (155)
Net income (loss) attributable to Diamondback Energy, Inc.	$ (4,525)	$ 110	$ (102)	$ (4,517)
Total assets	$ 16,128	$ 1,809	$ (318)	$ 17,619

18. 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, amortization and impairment are as follows:

	December 31, 2022	December 31, 2021
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 28,767	$ 24,418
Unproved properties	8,355	8,496
Total oil and natural gas properties	37,122	32,914
Accumulated depletion	(6,671)	(5,434)
Accumulated impairment	(7,954)	(7,954)
Net oil and natural gas properties capitalized	$ 22,497	$ 19,526

Costs incurred in oil and natural gas activities

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

	Year Ended December 31, 2022	2021	2020
	(In millions)		
Acquisition costs:			
Proved properties	$ 778	$ 2,805	$ 13
Unproved properties	1,536	1,829	106
Development costs	566	516	381
Exploration costs	1,698	1,223	1,098
Total	$ 4,578	$ 6,373	$ 1,598

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil, natural gas and natural gas liquids. It does not include any interest costs or general and administrative costs and income tax expense has been calculated by applying statutory income tax rates to oil, gas and natural gas liquids sales after deducting production costs, depreciation, depletion and amortization and accretion and impairment. Therefore, the following schedule is not necessarily indicative of the contribution to the net operating results of the Company’s oil, natural gas and natural gas liquids operations.

	Year Ended December 31, 2022	2021	2020
	(In millions)		
Oil, natural gas and natural gas liquid sales	$ 9,566	$ 6,747	$ 2,756
Production costs	(1,521)	(1,202)	(760)
Depreciation, depletion, amortization and accretion	(1,264)	(1,211)	(1,249)
Impairment	—	—	(6,021)
Income tax benefit (expense)	(1,437)	(918)	1,151
Results of operations	$ 5,344	$ 3,416	$ (4,123)

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates were and their associated future net cash flows were prepared by the Company's internal reservoir engineers and audited by Ryder Scott, independent petroleum engineers, as of December 31, 2022 and prepared by Ryder Scott as of December 31, 2021 and 2020. 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 the 12-month unweighted average of the first-day-of-the-month prices.

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.

The changes in estimated proved reserves are as follows:

	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBOE)
Proved Developed and Undeveloped Reserves:				
As of December 31, 2019	710,903	1,118,811	230,203	1,127,575
Extensions and discoveries	191,009	316,035	58,410	302,092
Revisions of previous estimates	(78,244)	300,160	21,927	(6,290)
Purchase of reserves in place	2,124	3,512	778	3,487
Divestitures	(209)	(905)	(141)	(501)
Production	(66,182)	(130,549)	(21,981)	(109,921)
As of December 31, 2020	759,401	1,607,064	289,196	1,316,441
Extensions and discoveries	271,222	720,125	127,479	518,722
Revisions of previous estimates	(160,570)	195,302	(6,685)	(134,705)
Purchase of reserves in place	176,261	302,770	58,587	285,310
Divestitures	(36,503)	(70,048)	(11,597)	(59,775)
Production	(81,522)	(169,406)	(27,246)	(137,002)
As of December 31, 2021	928,289	2,585,807	429,734	1,788,991
Extensions and discoveries	201,326	386,987	68,671	334,495
Revisions of previous estimates	(10,483)	2,827	3,228	(6,784)
Purchase of reserves in place	38,683	82,287	15,645	68,043
Divestitures	(6,691)	(12,671)	(2,079)	(10,882)
Production	(81,616)	(176,376)	(29,880)	(140,892)
As of December 31, 2022	1,069,508	2,868,861	485,319	2,032,971
Proved Developed Reserves:				
December 31, 2019	457,083	824,760	165,173	759,716
December 31, 2020	443,464	1,085,035	192,495	816,798
December 31, 2021	620,474	1,770,688	285,513	1,201,102
December 31, 2022	699,513	2,122,782	350,243	1,403,553
Proved Undeveloped Reserves:				
December 31, 2019	253,820	294,051	65,030	367,859
December 31, 2020	315,937	522,029	96,701	499,643
December 31, 2021	307,815	815,119	144,221	587,889
December 31, 2022	369,995	746,079	135,076	629,418

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, 2022, the Company's extensions and discoveries of 334,495 MBOE resulted primarily from the drilling of 654 new wells in which the Company has a working interest, including 576 wells in which we own only a mineral interest through Viper, and from 311 new proved undeveloped locations added. Viper royalty interests accounted for 8% of the extension volumes. The Company's downward revisions of previous estimates of 6,784 MBOE were the result of negative revisions of 98,902 MBOE due primarily to PUD downgrades related to changes in the corporate development plan following the FireBird Acquisition, partially offset with positive revisions of 92,118 MBOE associated with higher commodity prices. Purchases of 68,043 MBOE consisted of 67,037 MBOE attributable largely to the FireBird Acquisition and 1,005 MBOE of Viper royalty purchases. Divestitures of 10,882 MBOE related primarily to non-core Delaware Basin assets and the Eagle Ford Basin Divestiture.

During the year ended December 31, 2021, the Company's extensions and discoveries of 518,722 MBOE resulted primarily from the drilling of 470 new wells in which the Company has a working interest, including 345 wells in which we own only a mineral interest through Viper, and from 439 new proved undeveloped locations added. Viper royalty interests accounted for 6% of the extension volumes. The Company's downward revisions of previous estimates of 134,705 MBOE were the result of negative revisions of 268,560 MBOE due primarily to PUD downgrades related to changes in the corporate development plan following the QEP and Guidon acquisitions. These negative revisions were partially offset with positive revisions of 133,855 MBOE associated with higher commodity prices and improved well performance. Purchases of 285,309 MBOE primarily resulted from 276,207 MBOE attributable largely to the QEP Merger and Guidon Acquisition, and 9,102 MBOE of Viper royalty purchases, including the Swallowtail Acquisition. Divestitures of 59,775 MBOE related primarily to the Williston Basin Divestiture.

During the year ended December 31, 2020, the Company's extensions and discoveries totaling 302,092 MBOE resulted primarily from the drilling of 682 new wells in which the Company has a working interest and from 298 new proved undeveloped locations added. Viper royalty interests accounted for 8% of the extension volumes. The Company's downward revisions of previous estimates of 6,290 MBOE were the result of negative revisions due to lower product pricing of 54,645 MBOE, which were partially offset by positive revisions of 23,066 MBOE associated with a reduction in lease operating expenses, resulting in a total negative pricing revision of 31,579 MBOE. Downgrades of 31,074 MBOE are primarily from changes in the corporate development plan. These revisions were offset by positive performance revisions of 56,362 MBOE associated with less gas flaring and a corresponding increase in natural gas liquid recoveries.

At December 31, 2022, the Company's estimated PUD reserves were approximately 629,418 MBOE, an 41,529 MBOE increase over the reserve estimate at December 31, 2021 of 587,889 MBOE. The following table includes the changes in PUD reserves for 2022 (MBOE):

Beginning proved undeveloped reserves at December 31, 2021	587,889
Undeveloped reserves transferred to developed	(155,457)
Revisions	(82,619)
Purchases	8,734
Divestitures	(93)
Extensions and discoveries	270,964
Ending proved undeveloped reserves at December 31, 2022	629,418

The increase in proved undeveloped reserves was primarily attributable to extensions of 256,007 MBOE from 311 gross (287 net) wells in which the Company has a working interest and 14,957 MBOE from 199 gross wells in which Viper owns royalty interests. Of the 311 gross working interest wells, 261 were in the Midland Basin and 50 were in the Delaware Basin. Transfers of 155,457 MBOE from undeveloped to developed reserves were the result of drilling or participating in 168 gross (155 net) horizontal wells in which the Company has a working interest and 115 gross wells in which the Company also has a royalty interest or mineral interest through Viper. Downward revisions of 82,619 MBOE were primarily the result of negative revisions of 94,880 MBOE due to downgrades related to changes in the corporate development plan, and positive revisions of 12,261 MBOE attributable to higher commodity prices. Purchases of 8,734 MBOE consisted of 8,367 MBOE primarily from the FireBird Acquisition, and 367 MBOE of Viper royalty purchases.

As of December 31, 2022, all of the Company's proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2022, approximately $566 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on the unweighted arithmetic average, first-day-of-the-month price for the rolling 12-month period. 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.

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, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
	(In millions)		
Future cash inflows	$ 137,051	$ 77,085	$ 32,173
Future development costs	(6,176)	(4,243)	(3,585)
Future production costs	(25,295)	(19,123)	(10,763)
Future production taxes	(9,927)	(5,572)	(2,354)
Future income tax expenses	(17,563)	(7,237)	(727)
Future net cash flows	78,090	40,910	14,744
10% discount to reflect timing of cash flows	(42,391)	(22,193)	(7,986)
Standardized measure of discounted future net cash flows[1]	$ 35,699	$ 18,717	$ 6,758

(1) Includes $3.5 billion, $2.1 billion, and $1.0 billion, for the years ended December 31, 2022, 2021 and 2020, respectively, attributable to the Company's consolidated subsidiary, Viper, in which there is a 56% non-controlling interest at December 31, 2022.

The table below presents the unweighted arithmetic average first-day-of–the-month price for oil, natural gas and natural gas liquids utilized in the computation of future cash inflows:

	December 31,		
	2022	2021	2020
Oil (per Bbl)	$ 95.26	$ 64.78	$ 38.06
Natural gas (per Mcf)	$ 5.59	$ 2.61	$ 0.09
Natural gas liquids (per Bbl)	$ 39.40	$ 23.71	$ 10.83

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)

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,		
	2022	2021	2020
	(In millions)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 18,717	$ 6,758	$ 10,184
Sales of oil and natural gas, net of production costs	(8,045)	(5,757)	(2,225)
Acquisitions of reserves	1,473	1,914	30
Divestitures of reserves	(119)	(275)	(4)
Extensions and discoveries, net of future development costs	7,674	6,298	1,514
Previously estimated development costs incurred during the period	823	548	704
Net changes in prices and production costs	17,785	10,748	(5,273)
Changes in estimated future development costs	(317)	(19)	526
Revisions of previous quantity estimates	102	719	(462)
Accretion of discount	2,183	703	1,126
Net change in income taxes	(4,904)	(2,841)	807
Net changes in timing of production and other	327	(79)	(169)
Standardized measure of discounted future net cash flows at the end of the period	$ 35,699	$ 18,717	$ 6,758