Table of Contents

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, 2021
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 1200** **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. ☒

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, 2021 was approximately $16.9 billion.

As of February 18, 2022, 177,414,969 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2022 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, 2021

TABLE OF CONTENTS

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.
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.
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.
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.
Mcf	One thousand cubic feet of natural gas.
Mcf/d	One thousand cubic feet of natural gas per day.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	One million British Thermal Units.
MMcf	Million cubic feet of natural gas.
Net 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.
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 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.
2025 Indenture	The indenture relating to the 2025 Senior Notes, dated as of December 20, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
2025 Senior Notes	The Company’s 5.375% senior unsecured notes due 2025 issued under the 2025 indenture.
IG Indenture	The indenture dated as of December 5, 2019, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented by the supplemental indentures relating to the December 2019 Notes, the May 2020 Notes and the March 2021 Notes.
December 2019 Notes	The Company’s 2.875% senior unsecured notes due 2024, the Company’s 3.250% senior unsecured notes due 2026 and the Company’s 3.500% senior unsecured notes due 2029 issued under the IG indenture and the related first supplemental indenture.
May 2020 Notes	The Company’s 4.750% Senior Notes due 2025 issued under the IG Indenture and the related second supplemental indenture.
March 2021 Notes	The Company’s 0.900% Senior Notes due 2023, the Company’s 3.125% Senior Notes due 2031 and the Company’s 4.400% Senior Notes due 2051 issued under the IG Indenture and the related third supplemental indenture.
NYMEX	New York Mercantile Exchange.
Rattler	Rattler Midstream LP, a Delaware limited partnership.
Rattler’s General Partner	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.
Rattler LTIP	Rattler Midstream LP Long-Term Incentive Plan.
Rattler Offering	Rattler’s initial public offering.
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.
Senior Notes	The December 2019 Notes, the May 2020 Notes and the March 2021 Notes.
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;
- 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;
- 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 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 risk factors discussed in Item 1A of Part I of this Annual Report on Form 10-K.

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 two operating segments: (i) the upstream segment and (ii) the midstream operations segment, which includes midstream services.

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, 2021, our total acreage position in the Permian Basin was approximately 524,700 gross (445,848 net) acres, which consisted primarily of approximately 292,903 gross (265,562 net) acres in the Midland Basin and approximately 189,357 gross (148,588 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 and Eagle Ford Shale. We own Viper Energy Partners GP LLC, the general partner of Viper, which we refer to as Viper's general partner, and we own approximately 54% of the limited partner interests in Viper.

Further, our publicly traded subsidiary Rattler Midstream LP, which we refer to as Rattler, is focused on ownership, operation, development and acquisition of midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. We own Rattler Midstream GP LLC, the general partner of Rattler, which we refer to as Rattler's general partner, and we own approximately 74% of the limited partner interests in Rattler.

As of December 31, 2021, our estimated proved oil and natural gas reserves were 1,788,991 MBOE (which includes estimated reserves of 127,888 MBOE attributable to the mineral interests owned by Viper). Of these reserves, approximately 67% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 602 gross (533 net) horizontal well locations in which we have a working interest, and 17 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2021, our estimated proved reserves were approximately 52% oil, 24% natural gas liquids and 24% natural gas.

Significant 2021 Acquisitions and Divestitures

On February 26, 2021, we acquired 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.

On March 17, 2021, we acquired QEP Resources, Inc. ("QEP") in a transaction structured as a merger (the "QEP Merger"). The addition of QEP's assets increased our net acreage in the Midland Basin by approximately 49,000 net acres. Under the terms of the merger agreement with QEP, we issued approximately 12.12 million shares of our common stock to the former QEP stockholders, constituting a total value at the closing date of approximately $987 million.

On October 21, 2021, we completed the divestiture of our Williston Basin oil and natural gas assets, consisting of approximately 95,000 net acres acquired in the QEP Merger, for net cash proceeds of approximately $586 million after customary closing adjustments.

See Note 4—Acquisitions and Divestitures included in notes to the consolidated financial statements included elsewhere in this Annual Report for additional discussion of our acquisitions and divestitures during 2021.

COVID-19 and Effects on Commodity Prices

After briefly reaching negative levels in April 2020, oil prices recovered during 2021, closing at $85.43 per Bbl as of January 18, 2022 per Bbl WTI, spurred by the global economic recovery from the COVID-19 pandemic and producer restraint. Demand for oil and natural gas increased during 2021, as many restrictions on conducting business implemented in response to the COVID-19 pandemic were lifted due to improved treatments and availability of vaccinations in the U.S. and globally. The emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant, however, contributed to economic and pricing volatility as industry and market participants evaluated industry conditions and production outlook. Further, on January 4, 2022, OPEC and its non-OPEC allies, known collectively as OPEC+, agreed to continue their program (commenced in August of 2021) of gradual monthly output increases in February 2022, raising its output target by 400,000 Bbls per day, which move is expected to further boost oil supply in response to rising demand. In its report issued on February 10, 2022, OPEC noted its expectation that world oil demand will rise by 4.15 million Bbls per day in 2022 as the global economy continues to post a strong recovery from the COVID-19 pandemic. Although this demand outlook is expected to underpin oil prices, already seen at a seven-year high in February 2022, we cannot predict any future volatility in commodity prices or demand for crude oil.

Despite the recovery in commodity prices and rising demand, we kept our production relatively flat during 2021, using excess cash flow for debt repayment and/or return to our stockholders rather than expanding our drilling program.

Our Business Strategy

Our business strategy includes the following:

- **Exercise Capital Discipline.** During 2021, 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 well costs, which led to a total capital expenditure amount of $1.5 billion, down 11% from our guidance presented in April of 2021. We expect to continue to exercise capital discipline and plan to spend between $1.75 billion and $1.90 billion in 2022, with the goal of maintaining flat oil production throughout the year. This capital range accounts for the inflationary pressures we expect to see in 2022.

- **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 99% 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 85% 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 50% 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. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. During 2021, we completed the QEP Merger, which increased our net acreage in the Midland Basin by approximately 49,000 net acres. Also during 2021, we completed the Guidon Acquisition which included approximately 32,500 net acres in the Northern Midland Basin. These acquisitions, combined with our developmental activities, contributed to an increase in our total proved reserves of approximately 36% in 2021. 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, 2021, Diamondback had $595 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, 2021, Viper LLC had $39 million of cash and cash equivalents, $304 million in outstanding borrowings and $196 million available for future borrowings under its operating company's revolving credit facility. As of December 31, 2021, Rattler LLC had $20 million of cash and cash equivalents, $195 million in outstanding borrowings and $405 million available for future borrowings under its operating company's revolving credit facility.

- **Deliver on our commitment to ESG performance**. We are committed to the safe and responsible development of our resources in the Permian Basin. Our approach to environmental, social and governance ("ESG") matters is evidenced through our commitment to people, environmental responsibility, community and sound governance practices. Specifically, in February 2021, we announced significant enhancements to our ESG performance and disclosure, including Scope 1 and methane emission intensity reduction targets, as well as the implementation of our "Net Zero Now" initiative under which, effective January 1, 2021, we strive to produce every hydrocarbon with zero Scope 1 emissions. In September 2021, we announced our long-term goal to end routine flaring by 2025 and a long-term target to source over 65% of our water used for drilling and completion operations from recycled sources by 2025.

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, 2021 was approximately 60% oil, 20% natural gas liquids and 20% natural gas. As of December 31, 2021, our estimated net proved reserves were comprised of approximately 52% oil, 24% natural gas liquids and 24% natural gas.

- **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 9,314 gross (6,311 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 8,646 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 4,980 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. In addition, 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 99% 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.

- **Access to midstream infrastructure and gathering and transportation pipelines**. Through our publicly traded subsidiary Rattler and joint ventures in which it owns an interest, we have secured access to midstream infrastructure and crude oil and NGL gathering and transportation pipelines tailored to our expected levels of production in order to allow us the operational flexibility to execute on our business plan. Rattler is the primary provider of crude oil gathering and transportation and water sourcing and distribution service to us, with an acreage dedication that spans a total of approximately 450,000 gross acres across all of Rattler's service lines and over the core of the Midland and Delaware Basins.

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, 2021, our total acreage position in the Permian Basin was approximately 524,700 gross (445,848 net) acres, which consisted primarily of approximately 292,903 gross (265,562 net) acres in the Midland Basin and approximately 189,357 gross (148,588 net) acres in the Delaware Basin. In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 930,871 gross acres and 27,027 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 54% 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, 2021:

Basin	Number of Horizontal Wells
Midland	1,929
Delaware	856
Other	57
Total[(1)]	2,842

(1) Of these 2,842 total horizontal producing wells, we are the operator of 2,378 wells and have a non-operated working interest in 464 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, 2021:

	Average Days to Total Depth
Midland Basin	
7,500 foot lateral	10
10,000 foot lateral	11
13,000 foot lateral	13
Delaware Basin	
7,500 foot lateral	11
10,000 foot lateral	14
13,000 foot lateral	23

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

Our subsidiary, Rattler, is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Rattler's crude oil infrastructure assets consist of gathering pipelines and metering facilities, which collectively gather crude oil for its customers. Rattler's facilities gather crude oil from horizontal and vertical wells in our ReWard, Spanish Trail, Pecos and Fivestones areas within the Permian Basin. Rattler's water sourcing and distribution assets consists of water wells, frac pits, pipelines and water treatment and recycling facilities, which collectively gather and distribute water from Permian Basin aquifers to the drilling and completion sites through buried pipelines and temporary surface pipelines. Additionally, Rattler previously owned natural gas gathering assets, substantially all of which were divested in the fourth quarter of 2021. Subsequent to the divestiture of these assets, we utilize third party services and joint ventures in which Rattler owns equity interests discussed below for gathering and transportation of our natural gas production.

As of December 31, 2021, Rattler owned and operated 866 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. To facilitate the transportation of water and crude oil volumes away from the producing wellhead to ensure the efficient operations of a crude oil well, Rattler's midstream infrastructure includes a network of gathering pipelines that collect and transport crude oil and produced water from our operations in the Midland and Delaware Basins. We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include substantial acreage dedications.

As of December 31, 2021, Rattler also owned interests in the following 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, which began full operations in April 2020 and is referred to as the EPIC pipeline;
- 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, which began full operations in April 2020 and is referred to as the Gray Oak pipeline;
- a 4% equity interest in Wink to Webster Pipeline LLC, which is developing a crude oil pipeline that upon full commercial operations expected in the first quarter of 2022 will be capable of transporting approximately 1,500,000 Bbl/d from origin points at Wink and Midland in the Permian Basin for delivery to multiple Houston area locations;
- a 60% equity interest in OMOG JV LLC, which operates approximately 245 miles of crude oil gathering and regional transportation pipelines and approximately 200,000 barrels of crude oil storage in Midland, Martin, Andrews and Ector Counties, Texas; and
- a 25% equity interest in Remuda Midstream Holdings LLC, a joint venture that owns a majority interest in WTG Midstream LLC, which owns and operates 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.

For additional information regarding our equity method investments as of December 31, 2021, see Note 10—Equity Method Investments to our consolidated financial statements included elsewhere in this Annual Report.

Rattler also owns and operates certain real estate assets in Midland, Texas including the Fasken Center which has over 421,000 net rentable square feet within its two office towers.

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, 2021, we held working interests in 5,289 gross (4,430 net) producing wells and only royalty interests in 6,455 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 comingling 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 were conducive to the deposition 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 4,980 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.

Production Status

During the year ended December 31, 2021, net production from our acreage was 137,002 MBOE, or an average of 375,348 BOE/d, of which approximately 60% was oil, 20% was natural gas liquids and 20% was natural gas.

Recent and Future Activity

During 2022, we expect to drill an estimated 270 to 290 gross (248 to 267 net) operated horizontal wells and complete an estimated 260 to 280 gross (240 to 258 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2022 will be between $1.75 billion and $1.90 billion, consisting of $1.56 billion to $1.67 billion for horizontal drilling and completions including non-operated activity and capital workovers, $110 million to $130 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, 2021, we drilled 216 gross (203 net) and completed 275 gross (258 net) operated horizontal wells. During the year ended December 31, 2021, our capital expenditures for drilling, completing and equipping wells and infrastructure additions to oil and natural gas properties were $1.5 billion. In addition, we spent $30 million for oil and natural gas midstream assets.

We were operating 10 drilling rigs and four completion crews at December 31, 2021 and currently intend to operate between 10 and 12 rigs and three and four completion crews on average in 2022. 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

Our historical reserve estimates as of December 31, 2021, 2020 and 2019 were prepared by Ryder Scott with respect to our assets and those of Viper. Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing 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.

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, 2021 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. Approximately 95% of the 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. The remaining 5% of 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, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

The process of estimating oil, natural gas and natural gas liquids reserves is complex and requires significant judgment, as discussed in "Item 1A. Risk Factors" of this report. As a result, we maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve reports to discuss the assumptions and methods used in the proved reserve estimation 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.

Prior to his retirement effective December 31, 2021, our Executive Vice President and Chief Engineer was primarily responsible for overseeing the preparation of all our reserve estimates. Effective January 1, 2022, our Senior Vice President of Reservoir Engineering has assumed these responsibilities. We collectively refer to these individuals as the primary reserve engineers. The primary reserve engineers are petroleum engineers with over 30 and 18 years of reservoir and operations experience, respectively, and our geoscience staff has an average of approximately 15 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.

The preparation of our proved reserve estimates is completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, 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;
- direct reporting responsibilities by our Executive Vice President and Chief Engineer, prior to his retirement, to our Chief Executive Officer and by the current primary reserve engineer to our Executive Vice President—Operations;
- 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, 2021, 2020 and 2019 (including those attributable to Viper), based on the reserve reports prepared by Ryder Scott 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, 2021, none of our total proved reserves were classified as proved developed non-producing.

	As of December 31,		
	2021	2020	2019
Estimated Proved Developed Reserves:			
Oil (MBbls)	620,474	443,464	457,083
Natural gas (MMcf)	1,770,688	1,085,035	824,760
Natural gas liquids (MBbls)	285,513	192,495	165,173
Total (MBOE)	1,201,102	816,798	759,716
Estimated Proved Undeveloped Reserves:			
Oil (MBbls)	307,815	315,937	253,820
Natural gas (MMcf)	815,119	522,029	294,051
Natural gas liquids (MBbls)	144,221	96,701	65,030
Total (MBOE)	587,889	499,643	367,859
Estimated Net Proved Reserves:			
Oil (MBbls)	928,289	759,401	710,903
Natural gas (MMcf)	2,585,807	1,607,064	1,118,811
Natural gas liquids (MBbls)	429,734	289,196	230,203
Total (MBOE)[(1)]	1,788,991	1,316,441	1,127,575
Percent proved developed	67%	62%	67%

(1) Estimates of reserves as of December 31, 2021, 2020 and 2019 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, 2021, 2020 and 2019, 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 21—Supplemental Information on Oil and Natural Gas Operations for further discussion of our reserve estimates and pricing.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2021, our proved undeveloped reserves totaled 307,815 MBbls of oil, 815,119 MMcf of natural gas and 144,221 MBbls of natural gas liquids, for a total of 587,889 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 2021 (MBOE):

Beginning proved undeveloped reserves at December 31, 2020	499,643
Undeveloped reserves transferred to developed	(172,526)
Revisions	(243,268)
Purchases	63,013
Extensions and discoveries	441,027
Ending proved undeveloped reserves at December 31, 2021	587,889

The increase in proved undeveloped reserves was primarily attributable to extensions of 416,327 MBOE from 439 gross (383 net) wells in which we have a working interest and 24,700 MBOE from 336 gross wells in which Viper owns royalty interests. Of the 439 gross working interest wells, 409 were in the Midland Basin and 30 were in the Delaware Basin. Transfers of 172,526 MBOE from undeveloped to developed reserves were the result of drilling or participating in 154 gross (142 net) horizontal wells in which we have a working interest and 127 gross wells in which we have a royalty interest or mineral interest through Viper. We own a working interest in 106 of the 127 gross Viper wells. Downward revisions of 243,268 MBOE were the result of negative revisions of 260,494 MBOE due to downgrades related to changes in the corporate development plan following the QEP Merger and the Guidon Acquisition. These negative revisions were partially offset with positive revisions of 17,226 MBOE primarily attributable to higher commodity prices and improved well performance. Purchases of 63,013 MBOE were the result of 59,023 MBOE primarily from QEP and Guidon, and 3,990 MBOE of Viper's royalty interest purchases.

Costs incurred relating to the development of PUDs were approximately $516 million during 2021. Estimated future development costs relating to the development of PUDs are projected to be approximately $844 million in 2022, $1,053 million in 2023, $983 million in 2024 and $381 million in 2025. 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 9,314 gross (6,311 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 2022 by converting an estimated 25% of our PUDs to a proved developed category and developing approximately 86% of the consolidated 2021 year-end PUD reserves by the end of 2024. As of December 31, 2021, 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 identified economic potential horizontal drilling locations by basin:

	Number of Identified Economic Potential Horizontal Drilling Locations
Midland Basin	
Lower Spraberry(1)	1,107
Middle Spraberry(1)	923
Wolfcamp A(2)	791
Wolfcamp B(2)	974
Other	1,972
Total Midland Basin	5,767
Delaware Basin	
2nd Bone Springs(3)	718
3rd Bone Springs(3)	858
Wolfcamp A(4)	690
Wolfcamp B(4)	722
Other	559
Total Delaware Basin	3,547
Total	9,314

(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.
(4) Our current location count is based on 880 foot to 1,056 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)(2)	Total
Production Data:				
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
Year Ended December 31, 2019				
Oil (MBbls)	41,156	25,951	1,411	68,518
Natural gas (MMcf)	48,109	48,447	1,057	97,613
Natural gas liquids (MBbls)	10,485	7,826	187	18,498
Total (MBoe)	59,659	41,852	1,774	103,285

(1) Production data for the year ended December 31, 2021 includes the Eagle Ford Shale, Rockies and High Plains.
(2) Production data for the years ended December 31, 2020 and 2019 includes the Central Basin Platform, the Eagle Ford Shale and the Rockies.

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

	Year Ended December 31, 2021	2020	2019
Average Prices:			
Oil ($ per Bbl)	$ 66.19	$ 36.41	$ 51.87
Natural gas ($ per Mcf)	$ 3.36	$ 0.82	$ 0.68
Natural gas liquids ($ per Bbl)	$ 28.70	$ 10.87	$ 14.42
Combined ($ per BOE)	$ 49.25	$ 25.07	$ 37.63
Oil, hedged ($ per Bbl)(1)	$ 52.56	$ 40.34	$ 51.96
Natural gas, hedged ($ per Mcf)(1)	$ 2.39	$ 0.67	$ 0.86
Natural gas liquids, hedged ($ per Bbl)(1)	$ 28.33	$ 10.83	$ 15.20
Average price, hedged ($ per BOE)(1)	$ 39.87	$ 27.26	$ 38.00
Average Costs per BOE:			
Lease operating expenses	$ 4.12	$ 3.87	$ 4.74
Production and ad valorem taxes	3.10	1.77	2.40
Gathering and transportation expense	1.55	1.27	0.86
General and administrative - cash component	0.69	0.46	0.54
Total operating expense - cash	$ 9.46	$ 7.37	$ 8.54
General and administrative - non-cash component	$ 0.37	$ 0.34	$ 0.46
Depletion	8.77	11.30	13.54
Interest expense, net	1.45	1.79	1.66
Merger and integration expense	0.57	—	—
Total expenses	$ 11.16	$ 13.43	$ 15.66

(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 2021

The following table sets forth the total number of operated horizontal wells drilled and completed during the year ended December 31, 2021:

	Year Ended December 31, 2021			
	Drilled		Completed	
Area	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	175	165	207	194
Delaware Basin	41	38	64	61
Other	—	—	4	3
Total	216	203	275	258

As of December 31, 2021, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	2,215	2,056	1,731	1,606	3,946	3,662
Delaware Basin	29	26	647	609	676	635
Total	2,244	2,082	2,378	2,215	4,622	4,297

Productive Wells

As of December 31, 2021, we owned an interest in a total of 11,744 gross productive wells with an average unweighted 84% working interest in 5,289 gross (4,430 net) wells and an average 1.7% royalty interest in 6,455 additional wells. Through our subsidiary Viper, we own an average 3.3% net revenue interest in 9,095 of the total 11,744 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, 2021:

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Midland Basin	7,869	37	7,906	3,738	10	3,748
Delaware Basin	2,020	205	2,225	663	16	679
Other	1,467	146	1,613	3	—	3
Total productive wells	11,356	388	11,744	4,404	26	4,430

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, 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	—	—	—	—	—	—

	Year Ended December 31, 2019					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	75	68	31	28	106	96
Dry	—	—	—	—	—	—
Exploratory:						
Productive	96	86	128	114	224	200
Dry	—	—	—	—	—	—
Total:						
Productive	171	154	159	142	330	296
Dry	—	—	—	—	—	—

As of December 31, 2021, we had 24 gross (23 net) operated wells in the process of drilling and 129 gross (118 net) in the process of completion or waiting on completion.

Acreage

The following table sets forth information as of December 31, 2021 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage		Total Acreage(2)	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland	184,700	157,931	108,203	107,631	292,903	265,562
Delaware	97,000	71,418	92,357	77,169	189,357	148,587
Exploration	480	480	37,728	28,409	38,208	28,889
Conventional Permian	—	—	1,025	941	1,025	941
Other	3,207	1,868	—	1	3,207	1,869
Total	285,387	231,697	239,313	214,151	524,700	445,848

(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, 2021, 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		Exploratory		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2022	13,636	7,115	25,771	17,489	20,179	17,251	59,586	41,855
2023	3,969	124	13,049	9,347	—	—	17,018	9,471
2024	4,282	125	19,710	1,394	—	—	23,992	1,519
2025	—	—	160	160	—	—	160	160
2026	—	—	80	—	—	—	80	—
Total	21,887	7,364	58,770	28,390	20,179	17,251	100,836	53,005

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 on those properties, 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 on such property. 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, 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. For the year ended December 31, 2019, three 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 notes to the consolidated financial statements included elsewhere in this Annual Report.

Delivery Commitments

Certain of our firm sales agreements for oil include delivery commitments that specify the delivery of a fixed and determinable quantity. We believe our current production and reserves are sufficient to fulfill these delivery commitments and we expect such 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 18—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 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.

In our midstream operations segment, as Rattler seeks to expand its crude oil and water-related midstream services, it faces a high level of competition, including major integrated crude oil and natural gas companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store or market oil and natural gas. As Rattler seeks to expand to provide its midstream services to third party producers, it similarly faces a high level of competition. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas or natural gas liquids. Within the acreage dedicated by us to Rattler, Rattler does not compete with other midstream companies to provide us with midstream services as a result of our relationship and long-term dedications to Rattler's midstream assets. However, we may continue to use third party service providers for certain midstream services within such dedicated acreage until the expiration or termination of certain pre-existing dedications. Additionally, subsequent to the divestiture of substantially all of Rattler's natural gas gathering assets in the fourth quarter of 2021, third parties and joint ventures in which Rattler owns equity interests discussed above provide all of our natural gas gathering and transportation services.

Transportation

During the initial development of our fields we evaluate all gathering and delivery infrastructure in the areas of our production. Currently, a majority of our production in the Midland and Delaware Basins are transported to purchasers by pipeline.

The following table presents the average percentage of produced oil sold by pipeline and the average percentage of produced water connected to produced water disposal wells by pipeline:

	Midland Basin	Delaware Basin	Total
% of produced oil sold by pipeline	96 %	93 %	95 %
% of produced water transported by pipeline	98 %	99 %	99 %

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include an acreage dedication consisting of a total of approximately 450,000 gross acres across all Rattler's service lines located within the Midland and Delaware Basins.

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 (such as the severe winter storms in the Permian Basin in early 2021), 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 7, 2021, the EPA and the Corps published a proposed rule that would put back into place the pre-2015 definition of “waters of the United States,” updated to reflect Supreme Court decisions, while the agencies continue to consult with stakeholders on future regulatory actions. 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 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. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already 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 also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds 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. 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, the U.S. Geological Survey, and the U.S. Government Accountability Office, 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 and, 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 since indefinitely suspended some permits there and expanded the restrictions to other areas. These restrictions on use of produced water and a moratorium on new produced water disposal wells 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 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 our subsidiary Rattler LLC has 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 our subsidiary Rattler LLC, 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, Rattler LLC is 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.

Rattler LLC is 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 $225,134 and $2,251,334, 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. The safety enhancement requirements and other provisions of the Pipeline Safety and Job Creation Act and the PIPES Act, as well as any implementation of PHMSA rules thereunder and/or 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 selected 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 exclusion 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, 2021, we had approximately 870 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 an inclusive and respectful work environment. We deeply value the perspectives and experiences from our diverse personnel and are proud of our team, rich in a range of ethnic, cultural and ideological backgrounds. Nearly a third of our employees are women and over 25% of our employees self-identify as ethnic minorities. We took various actions during 2021 to increase the diversity in our candidate pool, and broaden our outreach, particularly within our college recruiting and internship programs, through various student organizations to support this inclusion effort 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 voluntary attrition rate, representing approximately 13% in 2021, despite the challenging labor market and increased competition for talent impacted by the COVID-19 pandemic. We believe that our low voluntary 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 SafeLandUSA orientation and training, which program is aligned with the International Association of Oil & Gas Producers Life Saving Rules and 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, recommended preventative measures based on reviewing vehicle and personnel incidents, safety and environmental audits at operational locations and audit and oversight of the Diamondback Hazard Communication Program.

From 2017 through 2021, 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 two in 2021, down from three in 2020. Our employee total recordable incident rate (TRIR) in 2021 was 0.25 in 2021 down from 0.42 in 2020 and lost-time incident rate (LTIR) was 0.12 in 2021 down from 0.14 in 2020. We have set a short-term target of maintaining an employee TRIR of 0.5 or less.

Training and Development

We support employees in pursuing training opportunities to expand their professional skills. Our internal course offerings in 2021 included a wide array of topics in addition to extensive safety and other compliance training sessions. Additionally, our people also 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.

Risk Factors Summary

The following is a summary of the principal risks that could adversely affect our business, operations and financial results. Please refer to Item 1A "Risk Factors" of this Form 10-K below for additional discussion of the risks summarized in this Risk Factors Summary.

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

- Our business and operations have been and will likely continue to be adversely affected by the ongoing COVID-19 pandemic and volatility in the oil and natural gas markets.
- 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.
- 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.
- Our hedging activities may limit or prevent our ability to take advantage of increased commodity prices, and despite such hedging activities, we may also be adversely affected by any declines in the price of oil or exposed to other risks, including counterparty credit risk.
- 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 these 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.
- Recent and future U.S. tax legislation may adversely 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.
- A reduction in availability under our revolving credit facility and the 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, Viper LLC's and Rattler 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.

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.

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

Our business and operations have been and will likely continue to be adversely affected by the ongoing COVID-19 pandemic and volatility in the oil and natural gas markets. In addition, if commodity prices decrease, our production, estimates of proved reserves and liquidity may be adversely affected.

After turning negative in April 2020, NYMEX WTI prices have recovered, closing at $85.43 per Bbl as of January 18, 2022, as demand for oil and natural gas increased and many restrictions on conducting business implemented in response to the COVID-19 pandemic were lifted due to improved treatments and availability of vaccinations in the U.S. and globally. The emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant, however, contributed to economic and pricing volatility as industry and market participants evaluated industry conditions and production outlook. Despite the recent recovery in demand for oil and natural gas and commodity prices, we have kept production on our acreage relatively flat during 2021, using excess cash flow for debt repayment and/or return to our stockholders rather than expanding our drilling program. We intend to continue exercising capital discipline by maintaining our oil production flat in 2022 at the fourth quarter 2021 level. 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 2021. 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 ongoing 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 are 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 treatments or vaccines against the virus or its new strains; the extent of 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; an increasingly competitive labor market due to a sustained labor shortage or increased turnover caused by the COVID-19 pandemic; increased logistics costs; additional costs due to remote working arrangements, adherence to 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.

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 any Russian-Ukrainian conflict 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 2021, NYMEX WTI prices ranged from $47.62 to $84.65 per Bbl and the NYMEX Henry Hub price of natural gas ranged from $2.45 to $6.31 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.

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 2021, our total capital expenditures, including expenditures for drilling, completion, infrastructure and additions to midstream assets, were approximately $1.5 billion. Our 2022 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $1.75 billion to $1.90 billion, representing an increase of 23% from our 2021 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 the 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 2022 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 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, 2021, we have approximately 9,314 gross (6,311 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, 2021, only 602 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, 2021, we have identified approximately 2,531 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, 2021, we are the operator of, have participated in, or have acquired working interest in a total of 2,842 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. In order to hold our current leases expiring in 2022, we will need to operate at least a one-rig program. 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.

We have entered into commodity price derivatives for a portion of our production. Although we have hedged a portion of our estimated 2022 and 2023 production, we may still be adversely affected by declines in the price of oil and may be exposed to other risks, including counterparty credit risk.

We use commodity price derivatives to reduce price volatility associated with certain of our oil and natural gas sales. To the extent that the prices of oil and natural gas remain at current levels or decline further, we may not be able to economically hedge future production at the same level as our current hedges, and our results of operations and financial condition may be negatively impacted.

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, 2021, see Note 15—Derivatives to our consolidated financial statements included elsewhere in this report.

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 decreased 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 $72 million at December 31, 2021) and receivables from purchasers of our oil and natural gas production (approximately $598 million at December 31, 2021). 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 "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 impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2021. Impairments of proved oil and natural gas properties of $6.0 billion and $0.8 billion were recorded for the years ended December 31, 2020 and 2019.

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 and our PV-10 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, and our related PV-10 calculation, 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 33% of our total estimated proved reserves as of December 31, 2021, 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 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, such as the severe winter storms in the Permian Basin in February 2021, and their adverse impact on production volumes, availability of electrical power, road accessibility and transportation facilities. 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, 2021, 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 “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 use of produced water and a moratorium on 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. These restrictions on the disposal of produced water and a moratorium on 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.

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.

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.

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. "Business—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 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 July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, which we refer to as Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, which we refer to as the CFTC, the SEC, and federal regulators of financial institutions, which we refer to as the Prudential Regulators, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes 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 many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the Mandatory Clearing Rule, requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps), a rule, which we refer to as the End User Exception, establishing an “end user” exception to the Mandatory Clearing Rule, a rule, which we refer to as the Margin Rule, setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the Non-Financial End User Exception, and a rule imposing position limits, which we refer to as the Position Limit Rule, and also an exception to the Position Limit Rule for swaps that constitute a “bona fide hedging transaction or position” within the definition of such term under the Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Position Limit Rule, which we refer to as the Bona Fide Hedging Exception.

We qualify for the End User Exception to the Mandatory Clearing Rule, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and each of our existing and anticipated hedging positions constitutes a “bona fide hedging transaction or position” under the Position Limit Rule and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the Bona Fide Hedging Exception under the Position Limit Rule, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write-down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as Foreign Regulations, which may apply to our transactions with counterparties subject to such Foreign Regulations, which we refer to as Foreign Counterparties, and the U.S. adopted law and rules, which we call the U.S. Resolution Stay Rules, clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation. The Dodd-Frank Act, the rules which have been adopted and not vacated, the Limit Rule and the U.S. Resolution Stay Rules 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. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulation, the U.S. Resolution Stay Rules and Foreign Regulations, our results of operations may become more volatile and our cash flows may be 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.

Future 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.

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 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.

Changes in environmental laws could increase our operating costs and adversely impact our business, financial condition and cash flows.

President Biden has indicated that he is supportive of, and has issued executive orders promoting, various programs and initiatives designed to, among other things, curtail climate change, control the release of methane from new and existing oil and natural gas operations, and decarbonize electric generation and the transportation sector. It remains unclear what additional actions President Biden will take and what support he will have for any potential legislative changes from Congress. Further, it is uncertain to what extent any new environmental laws or regulations, or any repeal of existing environmental laws or regulations, may affect our business or operations. However, such actions could significantly increase our operating costs or impair our ability to explore and develop other projects, which could adversely impact our business, financial condition and cash flows.

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.

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.

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

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. 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.

We have relied in the past, and we may rely from time to time in the future, on borrowings under our revolving credit facility to fund a portion of our capital expenditures. Unless we are able to repay borrowings under the revolving credit facility with cash flow from operations and proceeds from equity or debt offerings, implementing our capital programs may require an increase in our total leverage through additional debt issuances. In addition, a reduction in availability under our revolving credit facility and the 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.

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 general partner 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 general partner and Rattler’s subsidiaries are designated as unrestricted subsidiaries under the indentures governing our outstanding 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.

A breach of any of these restrictive covenants could result in default under the applicable debt instrument. If 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, 2021, see Note 11—Debt to our consolidated financial statements included elsewhere in this 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, Viper LLC's and Rattler 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 our subsidiaries' revolving credit facilities. The terms of our and our subsidiaries' revolving credit facilities provide for interest on borrowings at a floating rate equal to an alternate base rate tied to LIBOR. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve, which indicated plans for multiple interest rate increases in 2022, and other central banks, the supply of and demand for credit in the London interbank market 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. Our weighted average interest rate on borrowings under our revolving credit facility was 1.67% during the year ended December 31, 2021. Viper LLC's weighted average interest rate on borrowings from its revolving credit facility was 2.35% during the year ended December 31, 2021. Rattler LLC's weighted average interest rate on borrowings from its revolving credit facility was 1.41% during the year ended December 31, 2021. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

On July 27, 2017, the U.K. Financial Conduct Authority (the authority that regulates LIBOR), which we refer to as the FCA, announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. On March 5, 2021, the ICE Benchmark Administration, which administers LIBOR, and the FCA announced that all LIBOR settings will either cease to be provided by any administrator, or no longer be representative immediately after 2021, for all non-U.S. dollar LIBOR settings and one-week and two-month U.S. dollar LIBOR settings, and immediately after June 30, 2023 for the remaining U.S. dollar LIBOR settings. In light of these recent announcements, the future of LIBOR at this time is uncertain and any changes in the methods by which LIBOR is determined or regulatory activity related to LIBOR's phase-out could cause LIBOR to perform differently than in the past or cease to exist. Our current credit agreement provides for any changes away from LIBOR to a successor rate to be based on prevailing or equivalent standards, however, changes in the method of calculating LIBOR, or the discontinuation, reform, or replacement of LIBOR or any other benchmark rates may adversely affect interest rates and result in higher borrowing costs. This could materially and adversely affect our results of operations, cash flow and liquidity.

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 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 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, 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 billion of our outstanding common stock, of which $431 million had been repurchased through December 31, 2021. The stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time.

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, 2021, we had an NOL carryforward of approximately $2.5 billion and tax credits of $4 million for federal income tax purposes. Due to an ownership change on March 17, 2021 in conjunction with our acquisition of QEP in an all-stock transaction, our NOLs and tax credits, including those acquired from QEP, 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 limitation. Accordingly, we believe that the application of Section 382 as a result of this ownership change 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 contingencies, see Note 18—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 5,624 holders of record of our common stock on February 18, 2022.

Dividend Policy

The Company's board of directors has authority to declare dividends to the holders of the Company's common stock. The board of directors intends to continue the payment of dividends to the holders of the Company's common stock in the future. The decision to pay any future dividends 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.

Repurchases of Equity Securities

Our common stock repurchase activity for the three months ended December 31, 2021 was as follows:

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share(2)	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan(3)
	($ In millions, except per share amounts, shares in thousands)			
October 1, 2021 - October 31, 2021	2	$ 94.67	—	$ 1,978
November 1, 2021 - November 30, 2021	1,326	$ 106.25	1,326	$ 1,837
December 1, 2021 - December 31, 2021	2,533	$ 105.80	2,533	$ 1,569
Total	3,861	$ 105.95	3,859	

(1) Includes 2,308 shares of common stock repurchased from employees in order to satisfy tax withholding requirements. Such shares are cancelled and retired immediately upon repurchase.
(2) The average price paid per share includes any commissions paid to repurchase stock.
(3) In September 2021, the Company's board of directors authorized a $2 billion common stock repurchase program. 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. We operate in 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) through our subsidiary, Rattler, the midstream operations segment, which is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin.

We operate under a strategic approach that focuses predominantly on enhancing return through our low-cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. We are also committed to delivering results in a socially and environmentally responsible manner.

2021 Financial and Operating Highlights

- We recorded net income of $2.2 billion for the year ended December 31, 2021.
- Our average production was 137,002 MBOE/d during the year ended December 31, 2021.
- During the year ended December 31, 2021, we drilled 175 gross horizontal wells in the Midland Basin and 41 gross horizontal wells in the Delaware Basin.
- We turned 275 gross operated horizontal wells (including 207 in the Midland Basin and 64 in the Delaware Basin) to production and had capital expenditures, excluding acquisitions, of $1.5 billion during the year ended December 31, 2021.
- The average lateral length for the wells completed during the year ended December 31, 2021 was 10,602 feet.
- As of December 31, 2021, we had approximately 445,848 net acres, which primarily consisted of approximately 265,562 net acres in the Midland Basin and approximately 148,588 net acres in the Delaware Basin. As of December 31, 2021, we had an estimated 9,314 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 930,871 gross acres and 27,027 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 54% of these net royalty acres are operated by us.
- Our cash operating costs for the year ended December 31, 2021 were $9.46 per BOE, including lease operating expenses of $4.12 per BOE, cash general and administrative expenses of $0.69 per BOE and production and ad valorem taxes and gathering and transportation expenses of 4.65 per BOE.

2021 Transactions and Recent Developments

2021 Acquisition Activity and Recent Transactions

On February 26, 2021, we completed 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.

On March 17, 2021, we completed the QEP Merger. The addition of QEP's assets increased our net acreage in the Midland Basin by approximately 49,000 net acres. Under the terms of the merger agreement, we issued approximately 12.12 million shares of our common stock to the former QEP stockholders, with a total value of approximately $987 million on the closing date.

On October 1, 2021, Viper completed the acquisition of certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC (the “Swallowtail entities”) which included certain mineral and royalty interests for 15.25 million of Viper’s common units and approximately $225 million in cash (the “Swallowtail Acquisition”). The cash portion of the purchase price was funded through a combination of cash on hand and approximately $190 million of borrowings under Viper LLC’s revolving credit facility.

On October 5, 2021, Rattler and a private affiliate of an investment fund formed a joint venture entity, Remuda Midstream Holdings LLC (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 LLC (“WTG Midstream”).

2021 Divestiture Activity

On June 3, 2021 and June 7, 2021, respectively, we 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. We used our net proceeds from these transactions toward debt reduction.

On October 21, 2021, we completed the divestiture of our Williston Basin oil and natural gas assets, consisting of approximately 95,000 net acres acquired in the QEP Merger, for net cash proceeds of approximately $586 million after customary closing adjustments. We used our net proceeds from this transaction toward debt reduction.

On November 1, 2021, we completed the sale of certain gas gathering assets to Brazos Delaware Gas, LLC, which we refer to as Brazos, for net cash proceeds of approximately $54 million, after customary closing adjustments.

On December 1, 2021, we completed the sale of certain water midstream assets with a carrying value of approximately $160 million to Rattler in exchange for cash proceeds of approximately $160 million.

On November 1, 2021, Rattler completed the sale of its gas gathering assets to Brazos for net cash proceeds of approximately $83 million at closing, after customary closing adjustments, and an aggregate of $10 million in contingent payments.

See Note 4—Acquisitions and Divestitures for additional discussion of these transactions.

Debt Transactions

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 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 redemption of other senior notes outstanding as discussed further below.

Redemption of Notes

The net proceeds from the March 2021 Notes discussed above were primarily used to fund the repurchase of $1.65 billion in fair value carrying amount of the QEP Notes that remained outstanding at the effective time of the QEP Merger for total cash consideration of $1.7 billion, and $368 million principal amount of 2025 Senior Notes, for total cash consideration of $381 million. Giving effect to the repurchase of the 2023 Notes discussed below, these refinancing transactions are expected to result in an estimated annual interest cost savings of approximately $40 million in addition to an estimated $60 to $80 million of previously announced expected annual cost synergies from the QEP Merger.

In June 2021, we redeemed the remaining $191 million principal amount of outstanding legacy 4.625% senior notes due September 1, 2021 of Energen Corporation (“Energen”).

In August 2021 we redeemed the remaining $432 million principal amount of our outstanding 5.375% 2025 Senior Notes at a redemption price equal to 102.688% of the principal amount plus accrued interest. We funded the redemption with cash on hand and borrowings under our revolving credit facility.

On November 1, 2021, we redeemed the aggregate $650 million principal amount of our outstanding 2023 Notes with the proceeds received from the divestiture of our Williston Basin assets and cash on hand.

For additional discussion of our 2021 debt transactions and the amendment to the second amended and restated credit facility, see Note 11—Debt.

Fourth Quarter 2021 Dividend Declaration and Increase

On February 18, 2022, our board of directors declared a cash dividend for the fourth quarter of 2021 of $0.60 per share of common stock, payable on March 11, 2022 to our stockholders of record at the close of business on March 4, 2022, representing a 20% increase per share from the previously paid quarterly dividend.

Stock and Unit Repurchase Programs

During the year ended December 31, 2021, we repurchased approximately $431 million of Diamondback common stock, and as of December 31, 2021, $1.6 billion remained available for future purchases under our common stock repurchase program.

During the year ended December 31, 2021, Viper repurchased approximately $46 million of common units under its repurchase program. As of December 31, 2021, $80 million remained available for use to repurchase common units under Viper's common unit repurchase program.

During the year ended December 31, 2021, Rattler repurchased approximately $48 million of common units under its repurchase program. As of December 31, 2021, $88 million remained available for use to repurchase common units under Rattler's common unit repurchase program.

See "*—Liquidity and Capital Resources*" below for additional discussion.

COVID-19 and Effects on Commodity Prices

In early March 2020, oil prices dropped sharply and continued to decline, briefly reaching negative levels, as a result of multiple factors affecting the supply and demand in global oil and natural gas markets, including (i) actions taken by OPEC members and other exporting nations impacting commodity price and production levels and (ii) a significant decrease in demand due to the COVID-19 pandemic. Demand for oil and natural gas increased during 2021, as many restrictions on conducting business implemented in response to the COVID-19 pandemic were lifted due to improved treatments and availability of vaccinations in the U.S. and globally. As a result, oil and natural gas market prices have improved during 2021 in response to the increase in demand. During 2021 and 2020, the posted price for West Texas intermediate light sweet crude oil, or NYMEX WTI, has ranged from $(37.63) to $84.65 Bbl, and the NYMEX Henry Hub price of natural gas has ranged from $1.48 to $6.31 per MMBtu. On January 18, 2022, the closing NYMEX WTI price for crude oil was $85.43 per Bbl and the closing NYMEX Henry Hub price of natural gas was $4.28 per MMBtu. The emergence of the Delta COVID-19 variant in the latter part of 2021 and the subsequent surge of the highly transmissible Omicron variant, however, contributed to economic and pricing volatility as industry and market participants evaluated industry conditions and production outlook. Further, on January 4, 2021, OPEC and its non-OPEC allies, known collectively as OPEC+, agreed to continue their program (commenced in August of 2021) of gradual monthly output increases in February 2022, raising its output target by 400,000 Bbls per day, which is expected to further boost oil supply in response to rising demand. In its report issued on February 10, 2022, OPEC noted its expectation that world oil demand will rise by 4.15 million Bbls per day in 2022, as the global economy continues to post a strong recovery from the COVID-19 pandemic. Although this demand outlook is expected to underpin oil prices, already seen at a seven-year high in February 2022, we cannot predict any future volatility in commodity prices or demand for crude oil.

Despite the recovery in commodity prices and rising demand, we kept our production relatively flat during 2021, using excess cash flow for debt repayment and/or return to our stockholders rather than expanding our drilling program.

Outlook

During 2021, we continued building on our execution track record, generating free cash flow while keeping capital costs under control, and our efficiency gains, particularly in the Midland Basin drilling and completion programs, were able to mitigate certain inflationary pressures on well costs and led to a total capital expenditure amount of $1.5 billion down 11% from our guidance presented in April of 2021. We expect to continue to build on these operational efficiencies by controlling the variable portion of our operating and capital costs, which we believe will help mitigate the inflationary pressures seen across our business. We remain committed to capital discipline by maintaining flat oil production in 2022 and expect to maintain our best-in-class capital efficiency and cost structure. We expect to be in a position to continue to deliver on the recently announced enhanced capital return program, where we expect to distribute at least 50% of our quarterly free cash flow to our stockholders. Our capital return program is currently focused on our sustainable and growing dividend and a combination of stock repurchases and variable dividends. We expect to remain flexible on returning capital to our stockholders, depending on which method our board of directors believes presents the best return of capital to our stockholders at the relevant time.

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 have now drilled and completed a significant number of wells in Pecos, Reeves and Ward counties targeting the Wolfcamp A, which we believe has been de-risked across a significant portion of our total acreage position and remains our primary development target. In 2022, we expect to focus development on these areas.

As of December 31, 2021, we were operating 10 drilling rigs and four completion crews and currently intend to operate between 10 and 12 drilling rigs and between three and four completion crews in 2022 on average across our current acreage position in the Midland and Delaware Basins.

Environmental Responsibility Initiatives and Highlights

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 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 in our annual short-term incentive compensation plan to motivate our executives to advance our environmental responsibility goals.

In September 2021, we announced our long-term goal to end routine flaring by 2025 and a long-term target to source over 65% of our water used for drilling and completion operations from recycled sources by 2025. With respect to flaring, we flared 1.55% of our gross natural gas production in the fourth quarter of 2021. For the full year ended 2021, we flared 1.45% of our gross natural gas production, down 26% from 2020.

2022 Capital Budget

We have currently budgeted 2022 total capital spend of $1.75 billion to $1.90 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, 2021 and 2020. The midstream operations segment’s revenues and operating expenses were not significant to our consolidated statements of operations for the years ended December 31, 2021, 2020 and 2019. .For a discussion of the results of operations for the year ended December 31, 2020 as compared to the year ended December 31, 2019, 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, 2020 (filed with the SEC on February 25, 2021), 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, 2021	Year Ended December 31, 2020
Revenues (in millions):		
Oil sales	$ 5,396	$ 2,410
Natural gas sales	569	107
Natural gas liquid sales	782	239
Total oil, natural gas and natural gas liquid revenues	$ 6,747	$ 2,756
Production Data:		
Oil (MBbls)	81,522	66,182
Natural gas (MMcf)	169,406	130,549
Natural gas liquids (MBbls)	27,246	21,981
Combined volumes (MBOE)(1)	137,002	109,921
Daily oil volumes (BO/d)	223,348	180,825
Daily combined volumes (BOE/d)(1)	375,348	300,331
Average Prices:		
Oil ($ per Bbl)	$ 66.19	$ 36.41
Natural gas ($ per Mcf)	$ 3.36	$ 0.82
Natural gas liquids ($ per Bbl)	$ 28.70	$ 10.87
Combined ($ per BOE)	$ 49.25	$ 25.07
Oil, hedged ($ per Bbl)(2)	$ 52.56	$ 40.34
Natural gas, hedged ($ per Mcf)(2)	$ 2.39	$ 0.67
Natural gas liquids, hedged ($ per Bbl)(2)	$ 28.33	$ 10.83
Average price, hedged ($ per BOE)(2)	$ 39.87	$ 27.26

(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 tables provides information on the mix of our production for the years ended December 31, 2021 and 2020:

	Year Ended December 31, 2021	Year Ended December 31, 2020
Oil (MBbls)	60 %	60 %
Natural gas (MMcf)	20 %	20 %
Natural gas liquids (MBbls)	20 %	20 %
	100 %	100 %

Comparison of the Years Ended December 31, 2021 and 2020

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 $4.0 billion, or 145%, to $6.7 billion for the year ended December 31, 2021 from $2.8 billion for the year ended December 31, 2020. Higher average oil prices, and to a lesser extent natural gas and natural gas liquids prices, contributed $3.3 billion of the total increase. The remainder of the overall change is due to a 25% increase in combined volumes sold.

Higher commodity prices during 2021 compared to 2020 primarily reflect a recovery from historically low prices experienced in 2020 due to the COVID-19 pandemic as discussed in "—*2021 Transactions and Recent Developments*" above. The increase in production for 2021 compared to 2020 resulted primarily from the Guidon Acquisition and QEP Merger during the first quarter of 2021 and an overall recovery in our drilling and production activities after curtailments in the second quarter of 2020 in response to the COVID-19 pandemic. We expect to hold our oil production levels flat during 2022.

Lease Operating Expenses. The following table shows lease operating expenses for the years ended December 31, 2021 and 2020:

	Year Ended December 31,			
	2021		2020	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Lease operating expenses	$ 565	$ 4.12	$ 425	$ 3.87

Lease operating expenses for the year ended December 31, 2021 as compared to the year ended December 31, 2020 increased by $140 million, or $0.25 per BOE, primarily due to an increase in production between periods driven by the Guidon Acquisition and the QEP Merger in the first quarter of 2021. The increase on a per BOE basis is primarily related to the Williston Basin assets acquired in the QEP Merger which had higher lease operating costs per BOE on average than our historical properties. We completed the divestiture of the Williston Basin properties in October 2021.

Including the impact of our acquisition and divestiture activity in 2021 and future production plans, our total lease operating expenses in 2022 are expected to range from approximately $539 million to $618 million.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the years ended December 31, 2021 and 2020:

	Year Ended December 31,			
	2021		2020	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Production taxes	$ 349	$ 2.55	$ 135	$ 1.23
Ad valorem taxes	76	0.55	60	0.54
Total production and ad valorem expense	$ 425	$ 3.10	$ 195	$ 1.77
Production taxes as a % of oil, natural gas, and natural gas liquids revenue	5.2 %		4.9 %	

In general, production taxes are directly related to production revenues. Production taxes for the year ended December 31, 2021 increased by $214 million, or $1.32 per BOE. The increase in production taxes is attributable to an increase in commodity prices, as well as an increase in overall production due to assets acquired in 2021. The current year increase on a per BOE basis is primarily driven by an increase in current year commodity prices. Production taxes as a percentage of production revenues increased for the year ended December 31, 2021 compared to the year ended December 31, 2020 due primarily to the acquired Williston Basin properties which have a higher production tax rate than our other properties. We completed the divestiture of the Williston Basin properties in October 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, 2021 as compared to the year ended December 31, 2020 increased by $16 million primarily due to additional properties acquired in the Guidon Acquisition and the QEP Merger.

We expect production taxes to be approximately between 7% and 8% of oil, natural gas and natural gas liquids revenue during 2022.

Gathering and Transportation Expense. The following table shows gathering and transportation expense for the year ended December 31, 2021 and 2020:

	Year Ended December 31,			
	2021		2020	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Gathering and transportation expense	$ 212	$ 1.55	$ 140	$ 1.27

For the year ended December 31, 2021, the increase for gathering and transportation expenses are primarily attributable to the increase in production between periods. The current year increase on a per BOE basis is primarily driven by production added from the assets acquired in the QEP Merger which, in general, had higher average gathering and transportation costs per BOE than our historical properties, particularly those QEP assets located in the Williston Basin, which we divested in the fourth quarter of 2021. After giving effect to the 2021 acquisition and divestiture activities, we expect gathering and transportation expenses to range from approximately $212 to $243 million in 2022.

Midstream Services Expense. The following table shows midstream services expense for the years ended December 31, 2021 and 2020:

	Year Ended December 31,	
	2021	**2020**
	(In millions)	
Midstream services expense	$ 89	$ 105

Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities. In the fourth quarter of 2021, we and Rattler divested our natural gas gathering and transportation assets. Midstream services expense for the year ended December 31, 2021 as compared to the year ended December 31, 2020 decreased by $16 million primarily due to decreased maintenance costs, partially offset by increased fees for use of third party disposal systems.

Depreciation, Depletion, Amortization and Accretion. The following table provides the components of our depreciation, depletion and amortization expense for the years ended December 31, 2021 and 2020:

	Year Ended December 31,	
(In millions, except BOE amounts)	**2021**	**2020**
Depletion of proved oil and natural gas properties	$ 1,202	$ 1,242
Depreciation of midstream assets	48	44
Depreciation of other property and equipment	16	18
Asset retirement obligation accretion	9	7
Depreciation, depletion, amortization and accretion expense	$ 1,275	$ 1,311
Oil and natural gas properties depletion per BOE	$ 8.77	$ 11.30

The decrease in depletion of proved oil and natural gas properties of $40 million for the year ended December 31, 2021 as compared to the year ended December 31, 2020 resulted primarily from a reduction in the average depletion rate partially offset by increased production in 2021. The decline in rate resulted primarily from higher SEC oil prices utilized in the reserve calculations during 2021, lengthening the economic life of the reserve base and resulting in higher projected remaining reserve volumes on our wells.

Impairment of Oil and Natural Gas Properties. No impairment expense was recorded for the year ended December 31, 2021. 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.

As a result of the sharp decline in commodity prices during 2020, we recorded non-cash ceiling test impairments for the year ended December 31, 2020 of $6.0 billion which is included in accumulated depletion, depreciation, amortization and impairment on our consolidated balance sheet. Impairment charges affect our results of operations but do not reduce our cash flow. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices fall as compared to the commodity prices used in prior quarters, we may have material write-downs in subsequent quarters. See Note 8—Property and Equipment 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, 2021 and 2020:

	Year Ended December 31,			
	2021		2020	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
General and administrative expenses	$ 95	$ 0.69	$ 51	$ 0.46
Non-cash stock-based compensation	51	0.37	37	0.34
Total general and administrative expenses	$ 146	$ 1.06	$ 88	$ 0.80

General and administrative expenses for the year ended December 31, 2021 as compared to the year ended December 31, 2020 increased by $58 million primarily due to additional payroll and other employee driven costs of $32 million related to the QEP Merger and the Guidon Acquisition as well as $10 million of additional expense related to the implementation of a new enterprise resource planning system. Additionally, equity compensation for the year ended December 31, 2021 increased by $14 million compared to the same period in 2020.

We expect cash general and administrative expenses to range from approximately $87 million to $110 million in 2022, and non-cash stock-based compensation to range from approximately $54 million to $69 million in 2022.

Merger and Integration Expense. The following table shows merger and integration expense for the years ended December 31, 2021 and 2020:

	Year Ended December 31,			
	2021		2020	
(In millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Merger and integration expense	$ 78	$ 0.57	$ —	$ —

Total 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 for further details regarding the QEP Merger and the Guidon Acquisition.

Net Interest Expense. The following table shows net interest expense for the years ended December 31, 2021 and 2020:

	Year Ended December 31, 2021	2020
	(In millions)	
Revolving credit agreements	$ 11	$ 20
Senior notes	252	214
Amortization of debt issuance costs and discounts	18	12
Other	7	10
Capitalized interest	(88)	(55)
Total	200	201
Less: interest income	1	4
Interest expense, net	$ 199	$ 197

Net interest expense increased by $2 million for the year ended December 31, 2021 as compared to the year ended December 31, 2020. This increase primarily consisted of (i) $47 million in interest costs on the newly issued March 2021 Notes (ii) $25 million due to incurring a full year of interest expense in 2021 related to our May 2020 Notes and Rattler's 5.625% Senior Notes due 2025, and (iii) to a lesser extent, interest expense incurred on the QEP Notes that remained outstanding following the QEP Merger completed in March 2021. These increases were partially offset by (i) $33 million in additional capitalized interest costs, (ii) interest cost savings of $23 million on the repurchases of our 2025 Senior Notes in March 2021 and August 2021, (iii) $8 million on the repurchase of our 4.625% senior notes of Energen (iv) a $9 million reduction in borrowings under our revolving credit agreements during 2021, and (v) to a lesser extent, interest savings on the repurchase of our 2023 Notes in November 2021. We expect interest expense, net of interest income to range from approximately $148 million to $178 million in 2022. See Note 11—Debt for further details regarding outstanding borrowings and interest expense.

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, 2021 and 2020:

	Year Ended December 31, 2021	2020
	(In millions)	
Gain (loss) on derivative instruments, net	$ (848)	$ (81)
Net cash received (paid) on settlements(1)(2)(3)	$ (1,225)	$ 250

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

We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our commodity derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned "Gain (loss) on derivative instruments, net." As part of the QEP Merger, we received by novation from QEP certain derivative instruments which are included on our balance sheet as of December 31, 2021.

We have designated certain of our interest rate swaps as fair value hedges for accounting purposes. As a result, gains and losses due to changes in the fair value of the interest rate swaps completely offset changes in the fair value of the hedged portion of the underlying debt and no gain or loss is recognized due to hedge effectiveness. Changes in fair value are recorded as an adjustment to the carrying value of the 2029 Notes in the consolidated balance sheet. Beginning on December 1, 2021, we began recording semi-annual cash settlements of these interest rate swaps in interest expense in the consolidated statements of operations.

At December 31, 2021, we have a short-term derivative asset of $13 million, a long-term derivative asset of $4 million, a short-term derivative liability due in 2022 of $174 million and a long-term derivative liability due in 2023 of $29 million.

Provision for (Benefit from) Income Taxes. The following table shows the provision for (benefit from) income taxes for the years ended December 31, 2021 and 2020:

	Year Ended December 31,	
	2021	2020
	(In millions)	
Provision for (benefit from) income taxes	$ 631	$ (1,104)

The changes in our income tax provision for the year ended December 31, 2021 compared to the same period in 2020 were primarily due to the increase in pre-tax income for the year ended December 31, 2021.

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. At December 31, 2021, we had approximately $2.2 billion of liquidity consisting of $0.7 billion in cash and cash equivalents and $1.6 billion available under our credit facility. As discussed below, our capital budget for 2022 is $1.75 billion to $1.90 billion. Further, we have $45 million of senior notes maturities in the next 12 months.

Our working capital requirements are supported by our cash and cash equivalents and our 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 as discussed above, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, debt service obligations and repayment of debt maturities, stock repurchase program and other amounts that may ultimately be paid in connection with contingencies.

Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. In order to mitigate this volatility, we entered into derivative contracts with a number of financial institutions, all of which are participants in our credit facility, hedging a portion of our estimated future crude oil and natural gas production through the end of 2023 as discussed further in Note 15—Derivatives 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.

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 COVID-19 pandemic, the depressed commodity markets 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. Although the Company expects that its sources of funding will be adequate to fund its short-term and long-term liquidity requirements, we cannot assure you that the needed capital will be available on acceptable terms or at all.

Cash Flow

Our cash flows for the years ended December 31, 2021 and 2020 are presented below:

	Year Ended December 31,	
	2021	2020
	(In millions)	
Net cash provided by (used in) operating activities	$ 3,944	$ 2,118
Net cash provided by (used in) investing activities	(1,539)	(2,101)
Net cash provided by (used in) financing activities	(1,841)	(37)
Net change in cash	$ 564	$ (20)

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. See Item 1A. "Risk Factors" above.

The increase in operating cash flows for the year ended December 31, 2021 compared to the same period in 2020 primarily resulted from (i) an increase of $4.0 billion in our total revenues, and (ii) receipt of $152 million in refunds of income taxes receivable related to the carryback of federal net operating losses and the accelerated refund of minimum tax credits allowed under the CARES Act in 2020. These net cash inflows were partially offset by (i) a reduction of $1.5 billion due to making net cash payments of $1.2 billion on our derivative contracts in the year ended December 31, 2021 compared to receiving net cash of $250 million on our derivative contracts in the year ended December 31, 2020, (ii) an increase in our cash operating expenses of approximately $550 million primarily due to the QEP Merger and the Guidon Acquisition, and (iii) other working capital changes, primarily due to recording increases in accounts receivable, accounts payable and accrued capital expenditure activity stemming from the QEP Merger and the Guidon Acquisition in 2021. See "*—Results of Operations*" for discussion of significant changes in our revenues and expenses.

Investing Activities

Net cash used in investing activities was $1.5 billion compared to $2.1 billion for the years ended December 31, 2021 and 2020, respectively. The majority of our net cash used for 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 sale of our Williston Basin assets, leasehold acreage and other gathering assets discussed in Note 4—Acquisitions and Divestitures.

The majority of our net cash used in investing activities during the year ended December 31, 2020 was for drilling and completion costs in conjunction with our development program. 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,	
	2021	2020
	(In millions)	
Drilling, completions and non-operated additions to oil and natural gas properties[(1)(2)]	$ 1,334	$ 1,611
Infrastructure additions to oil and natural gas properties	123	108
Additions to midstream assets	30	140
Total	$ 1,487	$ 1,859

(1) During the year ended December 31, 2021, in conjunction with our development program, we drilled 216 gross (203 net) operated horizontal wells, of which 175 gross (165 net) wells were in the Midland Basin and 41 gross (38 net) wells were in the Delaware Basin, and turned 275 gross (258 net) operated horizontal wells to production, of which 207 gross (194 net) were in the Midland Basin and 64 gross (61 net) wells were in the Delaware Basin.

(2) During the year ended December 31, 2020, in conjunction with our development program, we drilled 208 gross (195 net) operated horizontal wells, of which 133 gross (125 net) wells were in the Midland Basin and 75 gross (70 net) wells were in the Delaware Basin, and turned 171 gross (159 net) operated horizontal wells to production, of which 93 gross (85 net) were in the Midland Basin and 78 gross (74 net) wells were in the Delaware Basin.

Financing Activities

Net cash used in financing activities for the year ended December 31, 2021 was $1.8 billion compared to net cash used in financing activities for the year ended December 31, 2020 of $37 million. During the year ended December 31, 2021, the amount used in financing activities was primarily attributable to (i) $3.2 billion paid for the repurchase of outstanding principal on certain senior notes as discussed in *"—Repurchases of Notes"* below, 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 from the March 2021 Notes, (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.

Net cash used in financing activities for the year ended December 31, 2020 was primarily attributable to $348 million of repayments, net of borrowings, on our credit facilities, $239 million in aggregate repayments on the Energen Notes and Viper Notes, $236 million in dividends paid to stockholders, $98 million of share repurchases as part of our stock repurchase program, and $93 million in distributions to non-controlling interest. These cash outlays were partially offset by net proceeds of $997 million from the issuance of the May 2020 Notes and the Rattler Notes during 2020.

Capital Resources

Revolving Credit Facilities and Other Debt Instruments

As of December 31, 2021, our debt, including the debt of Viper and Rattler, consists of approximately $6.2 billion in aggregate outstanding principal amount of senior notes, $499 million in aggregate outstanding borrowings under revolving credit facilities and $58 million in outstanding amounts due under our DrillCo Agreement.

At December 31, 2021, we have total principal payments due on our outstanding senior notes, including those of Viper and Rattler, of $45 million in 2022, $1.2 billion cumulatively in the years 2023 through 2024, $2.1 billion cumulatively in the years 2025 and 2026, and $3.4 billion thereafter. Additionally, we expect to incur future cash interest costs on these senior notes of approximately $177 million in 2022, $371 million in the years from 2023 through 2024, $277 million in the years from 2025 through 2026, and $961 million between 2027 and 2051.

On June 2, 2021, we entered into a twelfth amendment, or the Amendment, to the Second Amended and Restated Credit Agreement which, among other things, decreased the total revolving loan commitments from $2.0 billion to $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) upon election of the Borrower, subject to obtaining additional lender commitments and satisfaction of customary conditions). As of December 31, 2021, we had no outstanding borrowings under our revolving credit facility and $1.6 billion available for future borrowings under the revolving credit facility.

Viper's Revolving Credit Facility

Viper's credit agreement, as amended to date, 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, 2021, based on the Viper's oil and natural gas reserves and other factors. At December 31, 2021, Viper had elected a commitment amount of $500 million on its credit agreement with $304 million of outstanding borrowings. During the year ended December 31, 2021, the weighted average interest rate on borrowings under the Operating Company's revolving credit facility was 2.35%. Viper's Revolving credit facility matures in 2025.

Rattler's Revolving Credit Facility

Rattler's credit agreement provides for a revolving credit facility in the maximum credit amount of $600 million, which is expandable to $1.0 billion upon its election, subject to obtaining additional lender commitments and satisfaction of customary conditions. As of December 31, 2021, there was $195 million of outstanding borrowings under Rattler's revolving credit facility. The weighted average interest rate on borrowings under the credit agreement was 1.41% for the year ended December 31, 2021. Rattler's revolving credit facility matures in 2024.

During 2021, we issued an aggregate $2.2 billion of senior notes and redeemed $3.2 billion of senior notes outstanding.

For additional discussion of our outstanding debt as of December 31, 2021, see Note 11—Debt.

Subject to market conditions, we expect to continue to issue debt securities from time to time in the future to refinance our maturing debt. The availability, interest rate and other terms of any new borrowings will depend on the ratings assigned by credit rating agencies, among other factors.

We are currently in compliance, and expect to continue to be, with all financial maintenance covenants in our debt instruments.

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 rating from Standard and Poor's Global Ratings Services is BBB-. Our credit rating from Fitch Investor Services is BBB. Our credit rating from Moody's Investor Services is Baa3. Any rating downgrades may result in additional letters of credit or cash collateral being posted under certain contractual arrangements.

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 other contractual obligations and (iii) cash commitments for dividends and share repurchases as discussed below.

Based upon current oil and natural gas prices and production expectations for 2022, we believe that our cash flow from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through the 12-month period following the filing of this report and thereafter. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that the needed capital will be available on acceptable terms or at all. Further, our 2022 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

2022 Capital Spending Plan

Our board of directors approved a 2022 capital budget for drilling, midstream and infrastructure of $1.75 billion to $1.90 billion maintaining our annualized fourth quarter 2021 cash capital expenditure guidance presented in November of 2021. We estimate that, of these expenditures, approximately:

- $1.56 billion to $1.67 billion will be spent primarily on drilling 270 to 290 gross (248 to 267 net) horizontal wells and completing 260 to 280 gross (240 to 258 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 10,200 feet;
- $80 million to $100 million will be spent on midstream infrastructure, excluding joint venture investments; and
- $110 million to $130 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 were operating 10 drilling rigs and four completion crews at December 31, 2021 and currently intend to operate between 10 and 12 rigs and between three and four completion crews on average in 2022, as we continue to execute on our strategy to hold oil production flat while using cash flow from operations to reduce debt, strengthen our balance sheet and return capital to our stockholders. 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.

Other Contractual Obligations and Commitments

At December 31, 2021, our other significant contractual obligations consist primarily of (i) minimum transportation commitments totaling $878 million, (ii) asset retirement obligations totaling $171 million, and (iii) minimum purchase commitment for quantities of sand used in our drilling operations totaling $77 million. We expect to make aggregate payments of approximately $105 million for these commitments during 2022. See Note 9—Asset Retirement Obligations and Note 18—Commitments and Contingencies for further discussion of these and other contractual obligations and commitments.

Dividends and Share Repurchases

We paid common stock dividends of $312 million and $236 million during 2021 and 2020, respectively. On February 18, 2022, our board of directors declared a cash dividend for the fourth quarter of 2021 of $0.60 per share of common stock, payable on March 11, 2022 to our stockholders of record at the close of business on March 4, 2022. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors.

In September 2021, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock. The stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time. We repurchased approximately $431 million of our common stock under this program during the year ended December 31, 2021, and have $1.6 billion remaining for future repurchases under the repurchase program at December 31, 2021 See Note 12—Stockholders' Equity and Earnings Per Share for further discussion of the repurchase program.

Guarantor Financial Information

In connection with the merger of certain of the Company's wholly owned subsidiaries in an internal subsidiary restructuring on June 30, 2021, Diamondback E&P became the successor borrower to Diamondback O&G LLC ("O&G") under the credit agreement, the successor issuer of Energen's 7.125% Medium-term Notes, Series B, due February 15, 2028 and Energen's 7.32% Medium-term Notes, Series A, due July 28, 2022, and the sole guarantor under the indentures governing the December 2019 Notes, the May 2020 Notes, the 2025 Senior Notes and the March 2021 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 IG Indenture and the 2025 Indenture, 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. The 2025 Indenture was terminated in connection with the early redemption of the remaining $432 million principal amount of our 2025 Senior Notes in the third quarter of 2021.

Diamondback E&P's guarantees of the December 2019 Notes, the May 2020 Notes and the March 2021 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 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.

	December 31, 2021	
Summarized Balance Sheets:	**(In millions)**	
Assets:		
Current assets	$	1,148
Property and equipment, net	$	14,778
Other noncurrent assets	$	55
Liabilities:		
Current liabilities	$	1,221
Intercompany accounts payable, non-guarantor subsidiary	$	1,440
Long-term debt	$	5,093
Other noncurrent liabilities	$	1,549

	Year Ended December 31, 2021	
Summarized Statement of Operations:	**(In millions)**	
Revenues	$	5,049
Income (loss) from operations	$	2,898
Net income (loss)	$	1,348

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. Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and their associated future net cash flows. 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 reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future depletion of capitalized costs and result in impairment of assets that may be material. Revisions of previous reserve estimates accounted for approximately $719 million, or 6% of the change in the standardized measure of our total reserves from December 31, 2020 to December 31, 2021. No impairments were recorded on for our proved oil and gas properties during the year ended December 31, 2021; however, material impairments were recorded during the years ended December 31, 2020 and 2019 as discussed further in Note 8—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 2022.

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) on an annual basis 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, 2021, our unevaluated properties totaled $8 billion, which consisted of 214,151 net undeveloped leasehold acres with approximately 41,855 net acres set to expire in 2022. We did not record any impairment on our unevaluated properties during the year ended December 31, 2021, but any such future impairment could 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, 2021.

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 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 and Guidon 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.

The assessment of the realizability of our deferred tax assets, including the assessment of whether a valuation allowance is required, entails that we make estimates of, and assumptions about, future events, including the pattern of reversal of taxable temporary differences and our future income from operations. As of December 31, 2021, we had established a total valuation allowance of $315 million, including a valuation allowance for the full amount of Viper's deferred tax assets. 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. No such valuation allowance was determined to be necessary against Rattler's deferred tax assets as of December 31, 2021 based on the relative predictability of its future income stream based on its long term customer contracts. Any changes in the positive or negative evidence evaluated when determining if Viper's or Rattler'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, 2021, although the Company's recent cumulative losses represent negative evidence regarding reliance on future taxable income exclusive of reversing temporary differences, 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, 2021, 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 included in notes to the consolidated financial statements included elsewhere in this Annual Report for recent accounting pronouncements and accounting policies not yet adopted, if any.

Off-Balance Sheet Arrangements

Please read Note 18—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Form 10-K for a discussion of our 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 substantially due to rising energy use, easing of the COVID-19 pandemic restrictions, availability of treatments and vaccines in the U.S. and globally and improvements in the U.S. and global economic activity, we cannot predict events that may lead to future commodity price volatility. 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, 2021, we had a net liability derivative position of $168 million related to our commodity price derivatives. Utilizing actual derivative contractual volumes under our commodity price derivatives as of December 31, 2021, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position by $149 million to $317 million, while a 10% decrease in forward curves associated with the underlying commodity would have reduced the net liability derivative position by $117 million to $51 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.

In our midstream operations business, we have indirect exposure to commodity price risk in that persistent low commodity prices may cause us or Rattler's other customers to delay drilling or shut in production, which would reduce the volumes available for gathering and processing by our infrastructure assets. If we or Rattler's other customers delay drilling or temporarily shut in production due to persistently low commodity prices or for any other reason, our revenue in the midstream operations segment could decrease, as Rattler's commercial agreements do not contain minimum volume commitments.

For additional information on our open commodity derivative instruments at December 31, 2021, see Note 15—Derivatives.

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 $598 million at December 31, 2021), and to a lesser extent, receivables resulting from joint interest receivables (approximately $72 million at December 31, 2021).

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. The terms of our credit agreement provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.125% per annum in the case of the alternative base rate and from 1.25% to 2.125% per annum in the case of LIBOR, 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, 2021, see Note 11—Debt.

Historically, we have at times used interest rate swaps and treasury locks to reduce our exposure to variable rate interest payments associated with our revolving credit facility and changes in the fair value of our fixed-rate debt. At December 31, 2021, we have interest rate swap agreements for a notional amount of $1.2 billion to manage the impact of market interest rates on the fair value of our fixed-rate debt. These interest rate swaps have been designated as fair value hedges of the Company's $1.2 billion 3.50% fixed rate senior notes due 2029 whereby we will receive the fixed rate of interest and will pay an average variable rate of interest based on three month LIBOR plus 2.1865%. For additional information on our interest rate swaps, see Note 15—Derivatives.

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, 2021, 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, 2021, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

In July 2021, we implemented an enterprise resource planning system covering various financial and accounting processes. As a result of this implementation, certain internal controls over financial reporting have been automated, modified or implemented to address the new environment associated with the implementation of this system. We believe we have maintained appropriate internal control over financial reporting during the implementation and believe this new system will strengthen our internal control system. However, there are inherent risks in implementing any new system, and we will continue to evaluate these control changes as part of our assessment of 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, 2021 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, 2021.

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, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2021, 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, 2021, 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, 2021, 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, 2021, and our report dated February 24, 2022 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 24, 2022

ITEM 9B. OTHER INFORMATION

Effective February 21, 2022, our board of directors promoted Kaes Van't Hof, then our Chief Financial Officer and Executive Vice President—Business Development to the role of our President. In addition to his role as our President, Mr. Van't Hof will continue to serve as our Chief Financial Officer. Also, effective February 21, 2022, our board of directors promoted Daniel N. Wesson, then our Executive Vice President—Operations, to the role of our Chief Operating Officer. In addition to his role as our Chief Operating Officer, Mr. Wesson will continue to serve as our Executive Vice President.

Mr. Van't Hof's and Mr. Wesson's full biographies and, to the extent applicable, the information required by Item 404(a) of Regulation S-K, are included in our definitive proxy statement on Schedule 14A, filed by us with the SEC on April 23, 2021, which we refer to as our 2021 proxy statement. Each of Mr. Van't Hof and Mr. Wesson was named as our named executive officer in our 2021 proxy statement.

In connection with these promotions, the compensation committee of our board of directors approved increases in Mr. Van't Hof's and Mr. Wesson's annual base salaries to $625,000 and $560,000, respectively. In addition, the compensation committee also approved annual long-term equity incentive compensation awards with an intended grant date value of $3,750,000 for Mr. Van't Hof and $2,250,000 for Mr. Wesson to be granted under our equity incentive plan and represented by a combination of performance-based and time-based restricted stock units, vesting over applicable performance or service periods.

These executives will continue to participate in our annual executive cash incentive plan, which provides an opportunity to receive an annual bonus payable in a single lump sum, based on a target percentage of these executives' respective annual base salaries and such performance goals and criteria as determined in the discretion of the compensation committee of our board of directors, as well as in other employee benefit plans generally available to similarly situated employees, as in effect from time to time, a description of which is included in our 2021 proxy statement.

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, 2021.

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 "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, 2021.

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, 2021.

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, 2021.

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, 2021.

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).
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	Second 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 November 19, 2019).
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 Wells Fargo Bank, 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 5, 2019).
4.6	First Supplemental Indenture, dated as of December 5, 2019, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the form of 2024 Notes, 2026 Notes and 2029 Notes) (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).
4.7	Second Supplemental Indenture, dated as of May 26, 2020, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the form of Notes) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No 001-35700, filed by the Company with the SEC on May 26, 2020).
4.8	Third Supplemental Indenture, dated as of March 24, 2021, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the forms of 2023 Notes, 2031 Notes and 2051 Notes) (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).

3. Exhibits

Exhibit Number	Description
4.9	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).
4.10	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).
4.11	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).
4.12	Indenture, dated as of July 14, 2020, among Rattler Midstream LP, as issuer, Rattler Midstream Operating LLC, Tall City Towers LLC, Rattler Ajax Processing LLC, and Rattler OMOG LLC, as guarantors, and Wells Fargo Bank, National Association, as trustee (including the form of Rattler Midstream LP's 5.625% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-38919, filed by Rattler Midstream LP with the SEC on July 14, 2020).
4.13*	Supplemental Indenture, dated as of December 8, 2021, among Rattler WTG LLC, as guaranteeing subsidiary, Rattler Midstream LP, as issuer, Rattler Midstream Operating LLC, Tall City Towers LLC, Rattler OMOG LLC and Rattler Ajax Processing LLC, as the other guarantors, and Wells Fargo Bank, National Association, as trustee.
4.14*	Supplemental Indenture, dated as of December 22, 2021, among Rattler Holdings LLC, as guaranteeing subsidiary, Rattler Midstream LP, as issuer, Rattler Midstream Operating LLC, Tall City Towers LLC, Rattler OMOG LLC and Rattler Ajax Processing LLC, as the other guarantors, and Wells Fargo Bank, National Association, as trustee.
4.15	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).
4.16	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).
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).
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+	Form of Time-Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.7+	Form of Performance-Based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.8+	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).

3. Exhibits

Exhibit Number	Description
10.9+*	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).
10.10+	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).
10.11+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 2, 2014).
10.12+	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).
10.13	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	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).
10.21	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).
10.22	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).

3. Exhibits

Exhibit Number	Description
10.23	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).
10.24	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).
10.25	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).
10.26	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).
10.27	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).
10.28	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).
10.29	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).
10.30	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).
10.31	Credit Agreement, dated May 28, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.2 to Rattler Midstream LP's Form 8-K, File No. 001-38919, filed by Rattler Midstream LP with the SEC on May 29, 2019).
10.32	First Amendment to the Credit Agreement, dated as of October 23, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 of Rattler Midstream LP's Form 8-K (File 001-38919) filed on October 28, 2019).
10.33	Second Amendment, dated as of November 2, 2020, to the Credit Agreement, dated May 28, 2019, as amended on October 23, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto. (incorporated by reference to Exhibit 10.3 of Rattler Midstream LP's Quarterly Report on Form 10-Q (File 001-38919) filed on November 5, 2020).
10.34	Third Amendment to Credit Agreement, dated as of December 21, 2021, among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as administrative agent, and the lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 of Rattler Midstream LP's the Partnership's Quarterly Report on Form 10-Q (File 001-38919) filed on December 27, 2021).
10.35+	Transition and Consulting Agreement, entered into on November 30, 2021, between Diamondback Energy, Inc. and Russell Pantermuehl (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 30, 2021).
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).

3. Exhibits

Exhibit Number	**Description**
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P. with respect to the Diamondback Energy, Inc. reserve report included as Exhibit 99.1.
23.3*	Consent of Ryder Scott Company, L.P. with respect to the Viper Energy Partners LP reserve report included as Exhibit 99.2.
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*	Report of Ryder Scott Company, L.P., dated January 5, 2022, with respect to an estimate of the proved reserves, future production and income attributable to certain leasehold interests of Diamondback Energy, Inc. as of December 31, 2021.
99.2*	Report of Ryder Scott Company, L.P., dated January 5, 2022, with respect to an estimate 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, 2021.
101	The following financial information from the Company's Annual Report on Form 10-K for the year ended December 31, 2021, 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).

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* 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 24, 2022

/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 24, 2022
/s/ Vincent K. Brooks Vincent K. Brooks	Director	February 24, 2022
/s/ Michael P. Cross Michael P. Cross	Director	February 24, 2022
/s/ David L. Houston David L. Houston	Director	February 24, 2022
/s/ Stephanie K. Mains Stephanie K. Mains	Director	February 24, 2022
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 24, 2022
/s/ Melanie M. Trent Melanie M. Trent	Director	February 24, 2022
/s/ Steven E. West Steven E. West	Director	February 24, 2022
/s/ Kaes Van't Hof Kaes Van't Hof	President and Chief Financial Officer (Principal Financial Officer)	February 24, 2022
/s/ Teresa L. Dick Teresa L. Dick	Chief Accounting Officer, Executive Vice President and Assistant Secretary (Principal Accounting Officer)	February 24, 2022

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, 2021 and 2020, the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 24, 2022 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, the evaluation of impairment, and the valuation of oil and gas properties in the Guidon Acquisition and QEP Merger

As described in Note 2 to the financial statements, the Company accounts for its oil and 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 and measure its oil and gas properties for potential impairment. Additionally, as described in Note 4 to the financial statements, the Company acquired significant oil and gas properties during the year through the Guidon Acquisition and QEP Merger. To estimate the volume of proved reserves and future revenues, management makes significant estimates and assumptions, including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company’s development plan for proved undeveloped properties. Management also utilizes an estimated fair value pricing model for the valuation of acquired proved reserves. In addition, the estimation of proved reserves is also impacted by management’s judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment measurements. We identified the estimation of proved reserves of oil and gas properties, including acquired reserves, due to its impact on depletion expense, impairment evaluation, 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 relatively minor 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 or impairment expense, and the fair value of acquired oil and 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 the preparation of the ceiling test calculation, management’s estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company’s oil and gas properties for potential impairment, and management’s estimation of the fair value of the acquired oil and gas properties. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company’s accounting records, the management review controls on information provided to the reservoir engineering specialists, the management review controls on the final proved reserve report and on the final fair value reserve reports of the acquired oil and gas properties prepared by the Company’s specialists.

- We evaluated the level of knowledge, skill, and ability of the Company’s reservoir engineering specialists and their relationship to the Company, 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 by the Company’s specialists.

- To the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company’s accounting records, such as historical pricing differentials, operating costs, estimated capital costs and working and net revenue interests, we tested management’s process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management’s assumptions as follows:

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

  - Evaluated the models used to estimate the operating costs at year-end compared to historical operating costs;

  - Compared the models used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells with similar locations;

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

  - Evaluated the Company’s evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company’s intent to develop the proved undeveloped properties;

  - Evaluated the estimated ultimate recovery of proved undeveloped properties to the estimated ultimate recovery of comparable proved developed producing properties, on a sample basis; and

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

- To the extent key, sensitive inputs and assumptions used to determine the fair value of the acquired proved reserve volumes and other cash flow inputs were analyzed by testing management’s process for determining the assumptions, including examining the underlying support. Specifically, our audit procedures involved testing management’s assumptions as follows:

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

– Utilized a valuation specialist to evaluate whether the Company's valuation methodology was reasonable and performed a sensitivity analysis;

– Evaluated the appropriateness of the future operating cost and capital expenditure assumptions used in the fair value reserve report 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 land and division order records;

– Evaluated, on a sample basis, the appropriateness of management's estimated future production volumes and the production decline curves; and

– Compared the 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 24, 2022

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
	2021	2020
	(In millions, except par value and share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 654	$ 104
Restricted cash	18	4
Accounts receivable:		
Joint interest and other, net	72	56
Oil and natural gas sales, net	598	281
Inventories	62	33
Derivative instruments	13	1
Income tax receivable	1	100
Prepaid expenses and other current assets	28	23
Total current assets	1,446	602
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($8,496 million and $7,493 million excluded from amortization at December 31, 2021 and December 31, 2020, respectively)	32,914	27,377
Midstream assets	1,076	1,013
Other property, equipment and land	174	138
Accumulated depletion, depreciation, amortization and impairment	(13,545)	(12,314)
Property and equipment, net	20,619	16,214
Funds held in escrow	12	51
Equity method investments	613	533
Derivative instruments	4	—
Deferred income taxes, net	40	73
Investment in real estate, net	88	101
Other assets	76	45
Total assets	$ 22,898	$ 17,619
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 36	$ 71
Accrued capital expenditures	295	186
Current maturities of long-term debt	45	191
Other accrued liabilities	436	302
Revenues and royalties payable	452	237
Derivative instruments	174	249
Total current liabilities	1,438	1,236
Long-term debt	6,642	5,624
Derivative instruments	29	57
Asset retirement obligations	166	108
Deferred income taxes	1,338	783
Other long-term liabilities	40	7
Total liabilities	9,653	7,815
Commitments and contingencies (Note 18)		
Stockholders' equity:		
Common stock, $0.01 par value; 400,000,000 shares authorized; 177,551,347 and 158,088,182 shares issued and outstanding at December 31, 2021 and December 31, 2020, respectively	2	2
Additional paid-in capital	14,084	12,656
Retained earnings (accumulated deficit)	(1,998)	(3,864)
Total Diamondback Energy, Inc. stockholders' equity	12,088	8,794
Non-controlling interest	1,157	1,010
Total equity	13,245	9,804
Total liabilities and equity	$ 22,898	$ 17,619

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2021	2020	2019
	(In millions, except per share amounts, shares in thousands)		
Revenues:			
Oil sales	$ 5,396	$ 2,410	$ 3,554
Natural gas sales	569	107	66
Natural gas liquid sales	782	239	267
Midstream services	45	50	64
Other operating income	5	7	13
Total revenues	6,797	2,813	3,964
Costs and expenses:			
Lease operating expenses	565	425	490
Production and ad valorem taxes	425	195	248
Gathering and transportation	212	140	88
Midstream services expense	89	105	91
Depreciation, depletion, amortization and accretion	1,275	1,311	1,454
Impairment of oil and natural gas properties	—	6,021	790
General and administrative expenses	146	88	104
Merger and integration expense	78	—	—
Other operating expense	6	4	4
Total costs and expenses	2,796	8,289	3,269
Income (loss) from operations	4,001	(5,476)	695
Other income (expense):			
Interest expense, net	(199)	(197)	(172)
Other income (expense), net	(10)	(7)	9
Gain (loss) on derivative instruments, net	(848)	(81)	(108)
Gain (loss) on sale of equity method investments	23	—	—
Gain (loss) on extinguishment of debt	(75)	(5)	(56)
Income (loss) from equity investments	15	(10)	(6)
Total other income (expense), net	(1,094)	(300)	(333)
Income (loss) before income taxes	2,907	(5,776)	362
Provision for (benefit from) income taxes	631	(1,104)	47
Net income (loss)	2,276	(4,672)	315
Net income (loss) attributable to non-controlling interest	94	(155)	75
Net income (loss) attributable to Diamondback Energy, Inc.	$ 2,182	$ (4,517)	$ 240
Earnings (loss) per common share:			
Basic	$ 12.35	$ (28.59)	$ 1.47
Diluted	$ 12.30	$ (28.59)	$ 1.47
Weighted average common shares outstanding:			
Basic	176,643	157,976	163,493
Diluted	177,359	157,976	163,843
Dividends declared per share	$ 1.95	$ 1.5250	$ 0.9375

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	($ in millions, shares in thousands)					
Balance December 31, 2018	164,273	2	12,936	762	467	14,167
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	341	341
Net proceeds from issuance of common units - Rattler Midstream LP	—	—	—	—	720	720
Unit-based compensation	—	—	—	—	7	7
Common units issued for acquisition	—	—	—	—	124	124
Stock-based compensation	—	—	57	—	—	57
Cash paid for tax withholding on vested equity awards	—	—	(13)	—	—	(13)
Repurchased shares under buyback program	(6,385)	—	(598)	—	—	(598)
Distribution to non-controlling interest	—	—	—	—	(122)	(122)
Dividend paid	—	—	—	(112)	—	(112)
Exercise of stock and unit options and awards of restricted stock	1,114	—	8	—	—	8
Change in ownership of consolidated subsidiaries, net	—	—	(33)	—	45	12
Net income	—	—	—	240	75	315
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)
Distribution to non-controlling interest	—	—	—	—	(93)	(93)
Dividend paid	—	—	—	(236)	—	(236)
Exercise of stock options and vesting of restricted stock units	366	—	1	—	—	1
Change in ownership of consolidated subsidiaries, net	—	—	358	—	(366)	(8)
Net income (loss)	—	—	—	(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)
Distribution to non-controlling interest	—	—	—	—	(112)	(112)
Dividend paid	—	—	—	(312)	—	(312)
Exercise of stock options and issuance of restricted stock units and awards	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

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Cash flows from operating activities:			
Net income (loss)	$ 2,276	$ (4,672)	$ 315
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Provision for (benefit from) deferred income taxes	606	(1,042)	47
Impairment of oil and natural gas properties	—	6,021	790
Depreciation, depletion, amortization and accretion	1,275	1,311	1,454
(Gain) loss on extinguishment of debt	75	5	56
(Gain) loss on derivative instruments, net	848	81	108
Cash received (paid) on settlement of derivative instruments	(1,247)	250	80
Equity-based compensation expense	51	37	48
(Gain) loss on sale of equity method investments	(23)	—	—
Other	47	30	8
Changes in operating assets and liabilities:			
Accounts receivable	(196)	217	(187)
Income tax receivable	152	(62)	—
Prepaid expenses and other	20	2	29
Accounts payable and accrued liabilities	(41)	(20)	(129)
Revenues and royalties payable	148	(41)	135
Other	(47)	1	(15)
Net cash provided by (used in) operating activities	3,944	2,118	2,739
Cash flows from investing activities:			
Drilling, completions and infrastructure additions to oil and natural gas properties	(1,457)	(1,719)	(2,677)
Additions to midstream assets	(30)	(140)	(244)
Property acquisitions	(812)	(185)	(776)
Proceeds from sale of assets	820	63	300
Contributions to equity method investments	(114)	(102)	(485)
Distributions from equity method investments	9	40	—
Other	45	(58)	(6)
Net cash provided by (used in) investing activities	(1,539)	(2,101)	(3,888)
Cash flows from financing activities:			
Proceeds from borrowings under credit facilities	1,313	1,130	2,350
Repayments under credit facilities	(1,000)	(1,478)	(3,718)
Proceeds from senior notes	2,200	997	3,469
Repayment of senior notes	(3,193)	(239)	(1,250)
Proceeds from (repayments to) joint venture	(20)	40	39
Premium on extinguishment of debt	(178)	(2)	(44)
Public offering costs	—	—	(41)
Proceeds from public offerings	—	—	1,106
Repurchased shares under buyback program	(431)	(98)	(593)
Repurchased units under buyback program	(94)	(39)	—
Dividends to stockholders	(312)	(236)	(112)
Distributions to non-controlling interest	(112)	(93)	(122)
Financing portion of net cash received (paid) for derivative instruments	22	—	—
Other	(36)	(19)	(22)
Net cash provided by (used in) financing activities	(1,841)	(37)	1,062
Net increase (decrease) in cash and cash equivalents	564	(20)	(87)
Cash, cash equivalents and restricted cash at beginning of period	108	128	215
Cash, cash equivalents and restricted cash at end of period[(1)]	$ 672	$ 108	$ 128

1) See Note 2—Summary of Significant Accounting Policies

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. ("Diamondback" or the "Company") 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, 2021, 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 General Partner"), 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").

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 subsidiaries Viper and Rattler are consolidated in the financial statements of the Company. As of December 31, 2021, the Company owned approximately 54% of Viper's total units outstanding. The Company's wholly owned subsidiary, Viper Energy Partners GP LLC, is the general partner of Viper. As of December 31, 2021, the Company owned approximately 74% of Rattler's total units outstanding. The Company's wholly owned subsidiary, Rattler Midstream GP LLC, is the general partner of Rattler. The results of operations attributable to the non-controlling interest in Viper and Rattler are presented within equity and net income and are shown separately from the equity and net income attributable to the Company.

The Company reports its operations in 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.

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 and the effects of the ongoing COVID-19 pandemic. 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, the fair value determination of acquired assets and liabilities assumed, fair value estimates of derivative instruments and estimates of income taxes.

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.

The Company adopted Accounting Standards Update ("ASU") 2016-13 and the subsequent applicable modifications to the rule on January 1, 2020. 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 by considering 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, 2021 and 2020, 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. The Company accounts for its interest rate swaps which have been 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 completely offset changes in the fair value of the hedged portion of the underlying debt. For additional information regarding the Company's derivative instruments, see Note 15—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. Any income from services provided by subsidiaries to working interest owners of properties in which the Company also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties proportionate to the Company's investment in the subsidiary. 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 $8.77, $11.30 and $13.54 for the years ended December 31, 2021, 2020 and 2019, respectively. Depletion expense for oil and natural gas properties was $1.2 billion, $1.2 billion and $1.4 billion for the years ended December 31, 2021, 2020 and 2019, 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 8—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.

Real Estate Assets

Real estate assets 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. For additional information regarding the Company's real estate assets, see Note 7—Real Estate Assets.

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.

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 9—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, 2021, 2020 and 2019.

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 11—Debt for further details.

Inventories

Inventories are stated at the lower of cost or market and consist of tubular goods and equipment at December 31, 2021 and 2020. 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 11—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

Other accrued liabilities consist of the following:

	December 31,	
	2021	2020
	(In millions)	
Derivative liability payable	$ 101	$ 30
Lease operating expenses payable	86	115
Ad valorem taxes payable	70	57
Accrued compensation	48	27
Interest payable	46	37
Midstream operating expenses payable	13	18
Liability for drilling costs prepaid by joint interest partners	10	5
Other	62	13
Total other accrued liabilities	$ 436	$ 302

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 Rattler and are presented as a component of equity. When the Company's relative ownership interests in Viper and Rattler change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur. Because these changes in the ownership interests in Viper and Rattler 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 Rattler and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. See Note 12—Stockholders' Equity and Earnings Per Share for a discussion of changes of the Company's ownership interest in consolidated subsidiaries during the year ended December 31, 2021.

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.

Midstream Revenue

Substantially all revenues from gathering, compression, water handling, disposal and treatment operations are derived from intersegment transactions for services Rattler provides to exploration and production operations. The portion of such fees shown in the Company’s consolidated financial statements represent amounts charged to interest owners in the Company’s operated wells, as well as fees charged to other third parties for water handling and treatment services provided by Rattler or usage of Rattler’s gathering and compression systems. For gathering and compression revenue, Rattler satisfies its performance obligations and recognizes revenue when low pressure volumes are delivered to a specified delivery point. Revenue is recognized based on the per MMbtu gathering fee or a per barrel gathering fee charged by Rattler in accordance with the gathering and compression agreement. For water handling and treatment revenue, Rattler satisfies its performance obligations and recognizes revenue when the water volumes have been delivered to the frac-water meter for a specified well pad and the wastewater volumes have been metered downstream of the Company’s facilities. For services contracted through third party providers, Rattler’s performance obligation is satisfied when the service performed by the third party provider has been completed. Revenue is recognized based on the per barrel water delivery or a wastewater gathering and disposal fee charged by Rattler in accordance with the water services agreement.

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, 2021, 2020 and 2019 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.

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 also 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, the Company's share of the investee's earnings or loss is recognized in the consolidated statement of operations. As of December 31, 2021, the Company's proportionate share of the income or loss from equity method investments is recognized on a one-month lag for all 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 noncontrolling 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 loss has occurred, the Company would recognize an impairment provision. There were no material impairments of the Company's equity investments for the years ended December 31, 2021, 2020 and 2019. For additional information on the Company's investments, see Note 10—Equity Method Investments.

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 General Partner 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 13—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 14—Income Taxes.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In December 2019, the FASB issued ASU 2019-12, "Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes." This update is intended to simplify the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance and is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Company adopted this update effective January 1, 2021. 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 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

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.

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

	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

	Three Months Ended December 31, 2019			
	Midland Basin	Delaware Basin	Other	Total
	(In millions)			
Oil sales	$ 2,139	$ 1,351	$ 64	$ 3,554
Natural gas sales	32	33	1	66
Natural gas liquid sales	154	110	3	267
Total	$ 2,325	$ 1,494	$ 68	$ 3,887

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, 2021, three purchasers each accounted for more than 10% of our revenue: Vitol Inc. (“Vitol”) (21%); Shell Trading (USA) Company (“Shell”) (19%); and Plains Marketing LP (“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%). For the year ended December 31, 2019, three purchasers each accounted for more than 10% of the Company’s revenue: Shell (27%); Plains (23%); and Vitol (15%). 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

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 include 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 this transaction 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 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. Through December 31, 2021, there have been no material changes to the allocation presented in the March 31, 2021 10-Q filed with the SEC on May 7, 2021.

The following table sets forth the Company’s preliminary 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 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 since the acquisition date have been included in the consolidated statements of operations and include $345 million of total revenue and $170 million of net income for the year ended December 31, 2021.

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 11—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. Although the purchase price allocation is substantially complete as of the date of this filing, certain data necessary to complete the purchase price allocation is not yet available and includes, but is not limited to, final tax returns that provide the underlying tax basis of QEP's assets and liabilities and final valuations of the acquired oil and natural gas properties. As such, there may be further adjustments to the fair value of certain assets acquired and liabilities assumed. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date.

The following table sets forth the Company's preliminary 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		2,927
Other property, equipment and land		10
Deferred income taxes		40
Other assets		106
Amount attributable to assets acquired		3,294
Net assets acquired and liabilities assumed	$	987

The purchase price allocation above is 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 are 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, is 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 $742 million, primarily in the Midland Basin and the Williston Basin. The Williston Basin assets were divested in October 2021 as discussed further below. Through December 31, 2021, the fair value allocated to proved properties acquired in the QEP Merger has decreased by $300 million and the fair value allocated to unproved properties has increased by $300 million based on management's continuing assessment of the inputs utilized in the fair value estimates discussed above. There have been no other material changes to the allocation presented in the March 31, 2021 10-Q filed with the SEC on May 7, 2021.

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, 2021.

Pro Forma Financial Information

The following unaudited summary pro forma financial information for the years ended December 31, 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. 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 for the QEP Merger and the Guidon Acquisition of approximately $78 million for the year ended December 31, 2021 and acquisition-related costs incurred by QEP of $31 million 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,	
	2021	2020
	(In millions, except per share amounts)	
Revenues	$ 7,069	$ 3,727
Income (loss) from operations	$ 4,182	$ (5,771)
Net income (loss)	$ 2,186	$ (4,641)
Basic earnings per common share	$ 12.09	$ (25.67)
Diluted earnings per common share	$ 12.05	$ (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 $160 million, in a drop down transaction (the "Drop Down"). The midstream assets consist 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 $160 million. The Company and Rattler have also mutually agreed to amend 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 the Swallowtail entities 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 this transaction 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 $93 million, consisting of (i) $83 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.

2020 Activity

Viper's Acquisition of Certain Mineral and Royalty Interests

During the year ended December 31, 2020, Viper acquired, from unrelated third-party sellers, mineral and royalty interests representing 4,948 gross (417 net royalty) acres in the Permian Basin for an aggregate purchase price of approximately $64 million, including post-closing adjustments. Viper funded these acquisitions with cash on hand and borrowings under Viper LLC's revolving credit facility.

2019 Activity

Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

On May 23, 2019, the Company completed its divestiture of 6,589 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in its merger with Energen, for an aggregate sale price of $37 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company's reserve base or depreciation, depletion and amortization rate.

On July 1, 2019, the Company completed its divestiture of 103,750 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in the merger with Energen, for an aggregate sale price of $285 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company's reserve base or depreciation, depletion and amortization rate.

2019 Drop-Down Transaction

On July 29, 2019, the Company entered into a definitive purchase agreement to divest certain mineral and royalty interests to Viper for approximately 18 million of Viper's newly-issued Class B units, approximately 18 million newly-issued units of Viper LLC with a fair value of $497 million and $190 million in cash, after giving effect to closing adjustments for net title benefits. The mineral and royalty interests divested in the drop down transaction represented approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% were operated by the Company, and had an average net royalty interest of approximately 3.2%. The drop down transaction closed on October 1, 2019 and was effective as of July 1, 2019. Viper funded the cash portion of the purchase price of the drop down transaction through a combination of cash on hand and borrowings under Viper LLC's revolving credit facility.

5. VIPER ENERGY PARTNERS LP

Viper is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "VNOM". Viper was formed by Diamondback to, among other things, own, acquire and exploit oil and natural gas properties in the Permian Basin in North America. Viper LLC ("Viper's General Partner"), a wholly owned subsidiary of Diamondback, serves as the general partner of viper. As of December 31, 2021, Diamondback owned approximately 54% of Viper's total units outstanding.

In March 2019, Viper completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Viper received net proceeds from this offering of approximately $341 million, after deducting underwriting discounts and commissions and estimated offering expenses. There were no equity offerings during the years ended December 31, 2021 and 2020.

During the years ended December 31, 2021, 2020, and 2019, Diamondback received distributions of $101 million, $62 million and $133 million, respectively, in respect of its interests in Viper and Viper LLC.

The Company is party to a partnership agreement and tax sharing agreement with Viper which govern the reimbursement of various expenses and state, local and other taxes, respectively. No significant transactions occurred under these agreements during the years ended December 31, 2021, 2020 and 2019.

See Note 4—Acquisitions and Divestitures for discussions of Viper's acquisitions and divestitures.

Implementation of Viper's Common Unit Repurchase Program

On November 6, 2020, the board of directors of Viper's general partner approved a common unit repurchase program to acquire up to $100 million of Viper's outstanding common units. The common unit repurchase program was initially authorized to extended through December 31, 2021, but in November 2021, the board of directors of Viper's general partner increased the repurchase program authorization to $150 million and extended the program indefinitely. During the year ended December 31, 2021, Viper repurchased approximately $46 million of its common units under its repurchase program. As of December 31, 2021, $80 million remained available for use to repurchase common units under Viper's common unit repurchase program.

Viper LLC's Revolving Credit Facility

Viper has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, ("Wells Fargo") as administrative agent sole book runner and lead arranger. See Note 11—Debt for a description of this credit facility.

6. RATTLER MIDSTREAM LP

Rattler is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "RTLR". Rattler was formed by Diamondback in July 2018 to own, operate, develop and acquire midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Rattler Midstream GP LLC ("Rattler's General Partner"), a wholly owned subsidiary of Diamondback, serves as the general partner of Rattler. As of December 31, 2021, Diamondback owned approximately 74% of Rattler's total units outstanding.

Prior to the completion of Rattler's initial public offering (the "Rattler Offering") in May of 2019, Diamondback owned all of the general and limited partner interests in Rattler. The Rattler Offering consisted of 43,700,000 common units representing approximately 29% of the limited partner interests in Rattler at a price to the public of $17.50 per common unit. Rattler received net proceeds of approximately $720 million from the sale of these common units, after deducting offering expenses and underwriting discounts and commissions.

In connection with the completion of the Rattler Offering, Rattler (i) issued 107,815,152 Class B Units representing an aggregate 71% voting limited partner interest in Rattler in exchange for a $1 million cash contribution from Diamondback, (ii) issued a general partner interest in Rattler to Rattler's General Partner, in exchange for a $1 million cash contribution from Rattler's General Partner and (iii) caused Rattler LLC to make a distribution of approximately $727 million to Diamondback.

During the years ended December 31, 2021, 2020, and 2019, Diamondback received distributions of $97 million, $115 million and $36 million, respectively, in respect of its interests in Rattler and Rattler Midstream GP LLC.

The Company is party to a partnership agreement, services and secondment agreement and tax sharing agreement with Rattler which govern the reimbursement of various expenses and state, local and other taxes, respectively. No significant transactions occurred under these agreements during the years ended December 31, 2021, 2020 and 2019.

See Note 4—Acquisitions and Divestitures for discussions of Rattler's acquisitions and divestitures.

Implementation of Rattler's Common Unit Repurchase Program

On October 29, 2020, the board of directors of Rattler's general partner approved a common unit repurchase program to acquire up to $100 million of Rattler's outstanding common units. The common unit repurchase program was initially authorized to extend through December 31, 2021, but in October 2021, the board of directors of Rattler's general partner increased the repurchase program authorization to $150 million and extended the program indefinitely. During the year ended December 31, 2021, Rattler repurchased approximately $48 million of its common units under its repurchase program. As of December 31, 2021, $88 million remained available for use to repurchase common units under Rattler's common unit repurchase program.

Rattler LLC's Revolving Credit Facility

Rattler LLC has entered into a secured revolving credit facility with Wells Fargo, as administrative agent, sole book runner and lead arranger. See Note 11—Debt for a description of this credit facility.

7. REAL ESTATE ASSETS

The following schedules present the cost and related accumulated depreciation related to Diamondback's significant real estate assets:

	Estimated Useful Lives	December 31, 2021	December 31, 2020
	(Years)	(In millions)	
Buildings	20-30	$ 95	$ 102
Tenant improvements	5 - 15	4	5
Land	N/A	1	2
Land improvements	5 - 15	1	1
Total real estate assets		101	110
Less: accumulated depreciation		(16)	(13)
Total investment in land and buildings, net		$ 85	$ 97

8. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31, 2021	December 31, 2020
	(In millions)	
Oil and natural gas properties:		
Subject to depletion	$ 24,418	$ 19,884
Not subject to depletion	8,496	7,493
Gross oil and natural gas properties	32,914	27,377
Accumulated depletion	(5,434)	(4,237)
Accumulated impairment	(7,954)	(7,954)
Oil and natural gas properties, net	19,526	15,186
Midstream assets	1,076	1,013
Other property, equipment and land	174	138
Accumulated depreciation and impairment	(157)	(123)
Total property and equipment, net	$ 20,619	$ 16,214

Balance of costs not subject to depletion:	
Incurred in 2021	$ 1,688
Incurred in 2020	71
Incurred in 2019	422
Thereafter	6,315
Total not subject to depletion	$ 8,496

Capitalized internal costs were approximately $60 million, $53 million and $49 million for the years ended December 31, 2021, 2020 and 2019, 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. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed 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 year ended December 31, 2021. The Company recorded non-cash ceiling test impairments for the years ended December 31, 2020 and 2019 of $6.0 billion and $790 million, respectively, which are included in accumulated depletion, depreciation, amortization and impairment on the consolidated balance sheet. The impairment charge affected the Company's reported net income 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, 2021, there were $135 million in exploration costs and development costs and $124 million in capitalized interest that are not subject to depletion. At December 31, 2020, there were $85 million in exploration costs and development costs and $51 million capitalized interest that were not subject to depletion.

9. 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,	
	2021	2020
	(In millions)	
Asset retirement obligations, beginning of period	$ 109	$ 94
Additional liabilities incurred	11	13
Liabilities acquired	65	2
Liabilities settled and divested	(36)	(8)
Accretion expense	9	7
Revisions in estimated liabilities	13	1
Asset retirement obligations, end of period	171	109
Less: current portion(1)	5	1
Asset retirement obligations - long-term	$ 166	$ 108

(1) 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.

10. EQUITY METHOD INVESTMENTS

At December 31, 2021 and 2020, Rattler had the following investments:

	Ownership Interest	December 31, 2021	December 31, 2020
		(In millions)	
EPIC Crude Holdings, LP	10 %	$ 107	$ 121
Gray Oak Pipeline, LLC	10 %	121	130
Wink to Webster Pipeline LLC(1)	4 %	86	83
OMOG JV LLC	60 %	188	194
Amarillo Rattler, LLC(2)	— %	—	5
Remuda Midstream Holdings LLC	25 %	111	—
Total		$ 613	$ 533

(1) The Wink to Webster joint venture is developing a crude oil pipeline (the "Wink to Webster pipeline"). The Wink to Webster pipeline's main segment began interim service operation in the fourth quarter of 2020, and the joint venture is expected to begin full commercial operations in the first quarter of 2022.

(2) The ownership interest in Amarillo Rattler was 50% at December 31, 2020. See Note 4—Acquisitions and Divestitures for discussion regarding the sale of this equity method investment during the second quarter of 2021.

Income (loss) and distributions from Rattler's equity method investees were not material for the years ended December 31, 2021, 2020 or 2019.

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. Based on indicators present at December 31, 2021, the Company reviewed its investment in EPIC and determined the carrying value of the investment was less than its estimated fair value due to a reduction in expected future cash flow. However, based on the Company's review of various factors leading to the decline in the fair value of the investment, it was determined the carrying value of the EPIC investment will recover in the near term and therefore an other than temporary impairment in the carrying value of the EPIC equity method investment did not exist at December 31, 2021. However, should the conclusions on certain factors included in the Company's analysis, including estimates of EPIC's future cash flows, change, the Company may recognize an impairment that could materially impact it's consolidated financial statements. No significant impairments were recorded for Rattler's equity method investments for the years ended December 31, 2020 or 2019. Rattler'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 interim periods, it could result in circumstances requiring Rattler to record potentially material impairment charges on its equity method investments.

11. DEBT

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

	December 31, 2021	December 31, 2020
	(In millions)	
4.625% Notes due 2021[1]	$ —	$ 191
5.375% Senior Notes due 2022[3]	25	—
7.320% Medium-term Notes, Series A, due 2022[4]	20	20
5.250% Senior Notes due 2023[3]	10	—
2.875% Senior Notes due 2024	1,000	1,000
4.750% Senior Notes due 2025	500	500
5.375% Senior Notes due 2025[2]	—	800
3.250% Senior Notes due 2026	800	800
5.625% Senior Notes due 2026[3]	14	—
7.125% Medium-term Notes, Series B, due 2028[4]	100	100
3.500% Senior Notes due 2029	1,200	1,200
3.125% Senior Notes due 2031	900	—
4.400% Senior Notes due 2051	650	—
DrillCo Agreement[5]	58	79
Unamortized debt issuance costs	(31)	(29)
Unamortized discount costs	(28)	(27)
Unamortized premium costs	8	15
Fair value of interest rate swap agreements[6]	(18)	—
Revolving credit facility	—	23
Viper revolving credit facility	304	84
Viper 5.375% Senior Notes due 2027	480	480
Rattler revolving credit facility	195	79
Rattler 5.625% Senior Notes due 2025	500	500
Total debt, net	6,687	5,815
Less: current maturities of long-term debt	(45)	(191)
Total long-term debt	$ 6,642	$ 5,624

(1) In June 2021, the Company redeemed the remaining $191 million principal amount of outstanding legacy 4.625% senior notes due September 1, 2021 of Energen.
(2) In August 2021, the Company redeemed the remaining $432 million principal amount of its outstanding 5.375% 2025 Senior Notes.
(3) 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.
(4) In November 2018, Energen became the Company's wholly owned subsidiary and remained the issuer of these senior notes. In connection with the E&P Merger, Diamondback E&P became the successor issuer under the indenture.
(5) 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. As of December 31, 2021, the amount due to CEMOF related to this alliance was $58 million. As of December 31, 2021, fifteen joint wells under this agreement have been drilled and completed.
(6) The Company has two interest rate swap agreements in place on the Company's $1.2 billion 3.500% fixed rate senior notes due 2029. See Note 15—Derivatives for additional information on the Company's interest rate swaps designated as fair value hedges.

Debt maturities as of December 31, 2021, excluding debt issuance costs, premiums and discounts and fair value of interest rate swap premiums are as follows:

Year Ending December 31,		(In millions)
22	$	45
23		10
24		1,195
25		1,304
26		814
ereafter		3,388
tal	$	6,756

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 and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, as amended, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger. On June 2, 2021, Diamondback Energy, Inc., as parent guarantor, and O&G, as borrower (the “Borrower”), entered into a twelfth amendment (the “Amendment”) to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, with Wells Fargo Bank, National Association, as administrative agent (the “Administrative Agent”), and the lenders party thereto. The Amendment, among other things, (i) extended the maturity date to June 2, 2026, which may be further extended by two one-year extensions pursuant to the terms set forth in the credit agreement, (ii) decreased the total revolving loan commitments from $2.0 billion to $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) upon election of the Borrower, subject to obtaining additional lender commitments and satisfaction of customary conditions pursuant to the terms set forth in the credit agreement, (iii) added the ability of the Borrower to incur up to $100 million of the loans under the credit agreement as swingline loans and (iv) changed the interest rate applicable to the loans and certain fees payable under the credit agreement.

Outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Borrower that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50%, and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. After giving effect to the Amendment, (i) the applicable margin ranges from 0.250% to 1.125% per annum in the case of the alternate base rate, and from 1.250% to 2.125% per annum in the case of LIBOR, in each case based on the pricing level, and (ii) the commitment fee ranges from 0.150% to 0.350% per annum on the average daily unused portion of the commitments, based on the pricing level. The pricing level depends on certain ratings agencies’ ratings of the Company’s long-term senior unsecured debt.

On June 30, 2021, Diamondback E&P, as successor borrower to Diamondback O&G LLC, Diamondback Energy, Inc., as parent guarantor, and the Administrative Agent entered into a Successor Borrower Joinder Agreement (the “Joinder Agreement”) in connection with the E&P Merger. Pursuant to the Joinder Agreement, Diamondback E&P assumed all obligations (including, without limitation, all of the indebtedness) of O&G as the borrower under the credit agreement, the Second Amended and Restated Guaranty Agreement, dated as of November 20, 2019, made by O&G and Diamondback Energy, Inc., and the other documents entered into connection therewith.

As of December 31, 2021, the maximum credit amount available under the credit agreement is $1.6 billion which was fully available for future borrowings, except for an aggregate of $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 1.67%, 2.02% and 4.10% for the years ended December 31, 2021, 2020 and 2019, respectively.

Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage). Loan principal is required to be repaid (a) to the extent the loan amount exceeds the commitment due to any termination or reduction of the aggregate maximum credit amount and (b) at the maturity date of November 1, 2022.

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%. Our non-guarantor restricted subsidiaries may incur debt for borrowed money in an aggregate principal amount up to 15% of consolidated net tangible assets (as defined in the credit agreement) and we and our restricted subsidiaries may incur liens if the aggregate amount of debt secured by such liens does not exceed 15% of consolidated net tangible assets. As of December 31, 2021 and 2020, the Company was in compliance with all financial maintenance covenants under the revolving credit facility, as then in effect.

The lenders may accelerate all of the indebtedness under the revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

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 “—Redemptions of Diamondback 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.

The Company may redeem (i) the 2031 Notes in whole or in part at any time prior to December 24, 2030 and (ii) the 2051 Notes in whole or in part at any time prior to September 24, 2050, in each case at the redemption price set forth in the IG Indenture. If the 2031 Notes or the 2051 Notes are redeemed on or after the dates noted above, in each case, they may be redeemed at a redemption price equal to 100% of the principal amount of the 2031 Notes or 2051 Notes to be redeemed plus interest accrued thereon to but not including the redemption date.

Upon the occurrence of a change of control triggering event as defined in the IG Indenture, holders may require the Company to purchase some or all of its 2031 Notes or 2051 Notes for cash at a price equal to 101% of the principal amount being purchased, plus accrued and unpaid interest, if any, to the date of purchase.

2021 Redemptions of Notes

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, or 94.65%, of the outstanding fair value carrying amount of the QEP 2022 Notes, (ii) $663 million, or 98.43%, of the outstanding fair value carrying amount of the QEP 2023 Notes and (iii) $538 million, or 96.35%, 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% 2025 Senior Notes representing approximately 45.97% of the outstanding 2025 Senior Notes, 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 2025 Senior Notes 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.

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.

In August 2021, the Company redeemed the remaining $432 million principal amount of its outstanding 5.375% 2025 Senior Notes 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, 2021 of $12 million. The Company funded the redemption with cash on hand and borrowings under its revolving credit facility.

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.

Viper's Credit Agreement

On June 2, 2021, Viper LLC entered into the seventh amendment to the existing credit agreement, which (i) extended the maturity date under the credit agreement to June 2, 2025, (ii) changed the interest rates applicable to the loans under the credit agreement and certain fees payable under the credit agreement, and (iii) added a financial covenant requiring the ratio of secured debt to EBITDAX (as each is defined in the credit agreement) to be not greater than 2.50 to 1.0. On November 15, 2021, Viper LLC entered into the eighth amendment to the existing credit agreement, which maintained the maximum amount of the revolving credit facility of $2.0 billion, reaffirmed the borrowing base of $580 million based on Viper LLC's oil and natural gas reserves and other factors and added new provisions that allow Viper LLC to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be redetermined semi-annually in May and November. In addition, Viper LLC and Wells Fargo may each request up to three interim redeterminations of the borrowing base during any 12-month period. As of December 31, 2021, Viper LLC had elected a commitment amount of $500 million, with $304 million of outstanding borrowings and $196 million available for future borrowings under the Viper credit agreement.

The outstanding borrowings under the Viper credit agreement bear interest at a rate elected by Viper LLC that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% per annum in the case of the alternate base rate and from 2.00% to 3.00% per annum in the case of LIBOR, in each case depending on the amount of 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, which is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary breakage), and is required to be repaid (i) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (ii) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (iii) at the maturity date. The loan is secured by substantially all of the assets of Viper and Viper LLC. The weighted average interest rates on borrowings under the Viper credit agreement were 2.35%, 2.20%, and 4.51% for the years ended December 31, 2021, 2020 and 2019, respectively.

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $1.0 billion in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

As of December 31, 2021, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement. The lenders may accelerate all of the indebtedness under the Viper credit agreement upon the occurrence and during the continuance of any event of default. The Viper credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of the credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Rattler's Credit Agreement

In connection with the Rattler Offering, Rattler, as parent, and Rattler LLC, as borrower, entered into a credit agreement, dated May 28, 2019, with Wells Fargo, as administrative agent, and a syndicate of banks, as lenders party thereto (the "Rattler credit agreement").

The Rattler credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $600 million, which is expandable to $1.0 billion upon Rattler's election, subject to obtaining additional lender commitments and satisfaction of customary conditions. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary breakage), and is required to be paid at the maturity date of May 28, 2024. The Rattler credit agreement is guaranteed by Rattler, Tall City, Rattler OMOG LLC, Rattler Ajax Processing LLC, Rattler WTG LLC and Rattler Holdings and is secured by substantially all of the assets of Rattler and Rattler LLC. On December 21, 2021, Rattler, as parent, entered into a third amendment (the "Third Amendment") to the Credit Agreement, dated as of May 28, 2019, with Rattler LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders from time to time party thereto to, among other things, (i) permit the Rattler internal reorganization, including, without limitation, the formation of Rattler Holdings LLC ("Rattler Holdings") and the contribution of 100% of the limited liability company interests Rattler held in Rattler LLC to Rattler Holdings and (ii) provide for the addition of Rattler Holdings as a guarantor and restricted subsidiary. As of December 31, 2021, Rattler LLC had $ 195 million of outstanding borrowings and $405 million available for future borrowings under the Rattler credit agreement.

The outstanding borrowings under the Rattler credit agreement bear interest at a rate elected by Rattler LLC that is based on the prime rate or LIBOR, in each case plus an applicable margin. The applicable margin ranges from 0.250% to 1.250% per annum for prime-based loans and 1.250% to 2.250% per annum for LIBOR loans, in each case depending on the Consolidated Total Leverage Ratio (as defined in the Rattler credit agreement). Rattler LLC is obligated to pay a quarterly commitment fee ranging from 0.250% to 0.375% per annum on the unused portion of the commitment, which fee is also dependent on the Consolidated Total Leverage Ratio. The weighted average interest rates on borrowings under the Rattler credit agreement were 1.41%, 2.10%, and 3.13% for the years ended December 31, 2021, 2020 and 2019, respectively.

The Rattler credit agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, distributions and other restricted payments, transactions with affiliates, and entering into certain swap agreements, in each case of Rattler, Rattler LLC and their restricted subsidiaries. The covenants are subject to exceptions set forth in the Rattler credit agreement, including an exception allowing Rattler or Rattler LLC to issue unsecured debt securities and an exception allowing payment of distributions if no default exists.

The Rattler credit agreement also contains financial maintenance covenants that require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Consolidated Total Leverage Ratio	Not greater than 5.00 to 1.00 (or not greater than 5.50 to 1.00 for 3 fiscal quarters following certain acquisitions), but if the Financial Covenant Election (as defined in the Rattler credit agreement) is made, then not greater than 5.25 to 1.00)
Consolidated Senior Secured Leverage Ratio commencing with the last day of any fiscal quarter in which the Financial Covenant Election (as defined in the Rattler credit agreement) is made	Not greater than 3.50 to 1.00
Consolidated Interest Coverage Ratio (as defined in the Rattler credit agreement)	Not less than 2.50 to 1.00

As of December 31, 2021, Rattler LLC was in compliance with all financial maintenance covenants under the Rattler credit agreement. The lenders may accelerate all of the indebtedness under the Rattler credit agreement upon the occurrence and during the continuance of any event of default. The Rattler credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change in control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial maintenance covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. With certain specified exceptions, the terms and provisions of the Credit Agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2021, 2020 and 2019:

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Interest expense	$ 277	$ 250	$ 235
Other fees and expenses	11	6	4
Less: interest income	1	4	1
Less: capitalized interest	88	55	66
Interest expense, net	$ 199	$ 197	$ 172

12. STOCKHOLDERS' EQUITY AND EARNINGS PER SHARE

Diamondback did not complete any equity offerings during the years ended December 31, 2021, 2020 and 2019.

Stock Repurchase Programs

In September 2021, the Company's board of directors approved a stock repurchase program to acquire up to $2 billion of the Company's outstanding common stock. 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 year ended December 31, 2021, the Company repurchased approximately $431 million of common stock under this repurchase program, respectively. As of December 31, 2021, $1.6 billion remained available for use to repurchase shares under the Company's common stock repurchase program.

In May 2019, the Company's board of directors approved a stock repurchase program to acquire up to $2 billion of the Company's outstanding common stock through December 31, 2020. Purchases under the repurchase program were made from time to time in open market or privately negotiated transactions, and were subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program did not require the Company to acquire any specific number of shares. During the years ended December 31, 2020 and 2019, the Company repurchased $98 million and $598 million, respectively, of its common stock under the repurchase program. The repurchase program was suspended beginning in the first quarter of 2020 and expired on December 31, 2020.

Change in Ownership of Consolidated Subsidiaries

Non-controlling interests in the accompanying consolidated financial statements represent minority interest ownership in Viper and Rattler and are presented as a component of equity. The Company's ownership percentage in Viper and Rattler change 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 its units. These changes in ownership percentage and the disproportionate allocation of net income to the Company result in the difference between the Company's share of the underlying net book value in Viper and Rattler. When the Company's relative ownership interests in Viper and Rattler change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur.

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

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Net income (loss) attributable to the Company	$ 2,182	$ (4,517)	$ 240
Change in ownership of consolidated subsidiaries[(1)]	66	358	(33)
Change from net income (loss) attributable to the Company's stockholders and transfers to non-controlling interest	$ 2,248	$ (4,159)	$ 207

(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 Unitholders' Equity

For information regarding Viper's significant equity transactions, refer to Note 5—Viper Energy Partners LP.

Rattler Unitholders' Equity

For information regarding Rattler's significant equity transactions, refer to Note 6—Rattler Midstream LP.

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 and Rattler 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,		
	2021	2020	2019
	(In millions, except per share amounts, shares in thousands)		
Net income (loss) attributable to common stock	$ 2,182	$ (4,517)	$ 240
Weighted average common shares outstanding:			
Basic weighted average common shares outstanding	176,643	157,976	163,493
Effect of dilutive securities:			
Potential common shares issuable(1)(2)	716	—	350
Diluted weighted average common shares outstanding	177,359	157,976	163,843
Basic net income (loss) attributable to common stock	$ 12.35	$ (28.59)	$ 1.47
Diluted net income (loss) attributable to common stock	$ 12.30	$ (28.59)	$ 1.47

(1) For the year ended December 31, 2021, there were 115,865 potential common shares excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive under the treasury stock method.
(2) For the year ended December 31, 2020, there were 696,223 potential common shares excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive due to recording a net loss.

13. 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, 2021, the Company had 6.9 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, 2021, the Company had outstanding restricted stock units, performance-based restricted stock units, immaterial amounts of restricted share awards which were assumed in connection with the QEP Merger, and immaterial amounts of stock options and stock appreciation rights.

The following table presents the effects of the equity and stock based compensation plans and related costs:

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
General and administrative expenses	$ 51	$ 37	$ 48
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 20	$ 16	$ 17

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, 2021:

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2020	1,113,480	$ 48.58
Granted	776,045	$ 82.98
Vested	(713,777)	$ 65.07
Forfeited	(96,159)	$ 52.14
Unvested at December 31, 2021	1,079,589	$ 62.09

The aggregate fair value of restricted stock units that vested during the years ended December 31, 2021, 2020 and 2019 was $46 million, $25 million and $45 million, respectively. As of December 31, 2021, the Company's unrecognized compensation cost related to unvested restricted stock units was $ 52 million. Such cost is expected to be recognized over a weighted-average period of 2.0 years.

During the year ended December 31, 2020, the Company modified an insignificant amount of restricted stock units to include dividend equivalent rights during the vesting period which did not result in any incremental compensation costs.

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 2019, eligible employees received performance restricted stock unit awards totaling 199,723 units from which a minimum of 0% and a maximum of 200% units could be awarded based upon the TSR during the performance period of January 1, 2019 to December 31, 2021, subject to continued employment. All remaining awards under this grant cliff vested at December 31, 2021 at 100% based on the final TSR In March 2019, eligible employees received performance restricted stock unit awards totaling 32,958 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards had a performance period of January 1, 2019 to December 31, 2021 and were awarded at 100% based upon the final TSR. The awards under this grant vest in five equal installments beginning on March 1, 2025.

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 three-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%.

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:

	2021	2020	2019
Grant-date fair value	131.06	$ 70.17	$ 137.22
Grant-date fair value (5-year vesting)			$ 132.48
Risk-free rate	0.15 %	0.86 %	2.55 %
Company volatility	69.60 %	36.70 %	35.00 %

The following table presents the Company's performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2021:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2020	411,587	$ 99.10
Granted	198,454	$ 131.06
Vested	(153,582)	$ 137.22
Forfeited	—	$ —
Unvested at December 31, 2021[(1)]	456,459	$ 100.17

(1) A maximum of 1,091,711 units could be awarded based upon the Company's final TSR ranking.

As of December 31, 2021, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $26 million, which is expected to be recognized over a weighted-average period of 1.9 years.

Rattler Long-Term Incentive Plan

On May 22, 2019, the board of directors of Rattler's General Partner adopted the Rattler Midstream LP Long Term Incentive Plan ("Rattler LTIP") which authorized a total of 15.2 million common units for issuance, for employees, consultants and directors of Rattler's General Partner and any of its affiliates, including Diamondback, who perform services for Rattler. The Rattler LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. Excluding unvested common units, as of December 31, 2021, a total of 12,696,146 common units had been reserved for future issuance pursuant to the Rattler LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The Rattler LTIP is administered by the board of directors of Rattler's General Partner or a committee thereof.

Under the Rattler LTIP, the board of directors of Rattler's General Partner is authorized to issue phantom units to eligible employees and non-employee directors. Rattler estimates the fair value of phantom units based on closing price of Rattler's common units on the grant date of the award, and expenses this value over the applicable vesting period. Upon vesting, the phantom units entitle the recipient to one common unit of Rattler for each phantom unit. The recipients are also entitled to distribution equivalent rights, which represent the right to receive a cash payment equal to the value of the distributions paid on one phantom unit between the grant date and the vesting date.

The following table presents the phantom unit activity under the Rattler LTIP for the year ended December 31, 2021:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2020	2,089,668	$ 17.07
Granted	259,916	$ 11.07
Vested	(571,341)	$ 16.34
Forfeited	(40,718)	$ 7.28
Unvested at December 31, 2021	1,737,525	$ 16.64

The aggregate fair value of phantom units that vested during the year ended December 31, 2021 was $9 million. As of December 31, 2021, the unrecognized compensation cost related to unvested phantom units was $23 million which is expected to be recognized over a weighted-average period of 2.3 years.

14. 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, Rattler and Rattler LLC, file a federal corporate income tax return on a consolidated basis. As discussed further below, Viper is 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. Subsequent to Rattler's election to be treated as a corporation for federal income tax purposes effective May 24, 2019, Rattler is also a taxable entity and as such files a federal corporate income tax return including the activity of its investment in Rattler LLC. Viper's and Rattler'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.

The Company's effective income tax rates were 21.7%, 19.1% and 13.0% for the years ended December 31, 2021, 2020 and 2019, respectively. Total income tax expense 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 benefit 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. Total income tax expense for the year ended December 31, 2019 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to the impact of deferred taxes recognized as a result of Viper's change in tax status and state income taxes net of federal benefit.

The Company considered the impact of the American Rescue Plan Act, enacted on March 11, 2021, and concluded its provisions related to U.S. income taxes for corporations did not materially affect the Company's current or deferred tax balances. Under provisions enacted March 27, 2020 in the Coronavirus Aid, Relief, and Economic Security Act ("CARES Act"), the Company realized income tax benefit of $25 million in the period of enactment related to the carryback of approximately $179 million of the Company's federal net operating losses to tax years in which the corporate income tax rate was 35%. Prior to the enactment of the CARES Act in the first quarter of 2020, there was no tax refund available to the Company with respect to its losses, resulting in deferred tax assets associated with federal net operating loss carryforwards at the statutory 21% corporate income tax rate. As a result of the refund associated with such carryback as well as the accelerated refund available for minimum tax credits, the Company received a refund of federal taxes in the first quarter of 2021 of approximately $100 million. In addition, the Company received in the third quarter of 2021 a federal tax refund of approximately $50 million related to refundable minimum tax credits resulting from carryback of certain federal net operating losses acquired from QEP.

The components of the Company's consolidated provision for income taxes from continuing operations for the years ended December 31, 2021, 2020 and 2019 are as follows:

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Current income tax provision (benefit):			
Federal	$ 10	$ (62)	$ —
State	15	—	—
Total current income tax provision (benefit)	25	(62)	—
Deferred income tax provision (benefit):			
Federal	594	(1,010)	40
State	12	(32)	7
Total deferred income tax provision (benefit)	606	(1,042)	47
Total provision for (benefit from) income taxes	$ 631	$ (1,104)	$ 47

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

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Income tax expense at the federal statutory rate (21%)	$ 610	$ (1,213)	$ 76
Income tax benefit relating to net operating loss carryback	—	(25)	—
State income tax expense, net of federal tax effect	23	(30)	6
Non-deductible compensation	10	6	4
Change in valuation allowance	(12)	153	—
Deferred taxes related to change in Viper LP's tax status	—	—	(42)
Other, net	—	5	3
Provision for (benefit from) income taxes	$ 631	$ (1,104)	$ 47

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

The components of the Company’s deferred tax assets and liabilities as of December 31, 2021 and 2020 are as follows:

	December 31, 2021	December 31, 2020
	(In millions)	
Deferred tax assets:		
Net operating loss and other carryforwards	$ 682	$ 524
Derivative instruments	36	60
Stock based compensation	5	7
Viper's investment in Viper LLC	163	150
Rattler's investment in Rattler LLC	40	58
Other	22	8
Deferred tax assets	948	807
Valuation allowance	(315)	(166)
Deferred tax assets, net of valuation allowance	633	641
Deferred tax liabilities:		
Oil and natural gas properties and equipment	1,702	1,156
Midstream investments	224	192
Other	5	3
Total deferred tax liabilities	1,931	1,351
Net deferred tax liabilities	$ 1,298	$ 710

The Company had net deferred tax liabilities of approximately $1.3 billion and $0.7 billion at December 31, 2021 and 2020, respectively.

At December 31, 2021, the Company had approximately $0.5 billion of federal NOLs expiring in 2037 and $2.0 billion of federal NOLs with an indefinite carryforward life, including NOLs acquired from QEP. 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, 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 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. As of December 31, 2021, QEP’s opening balance sheet net deferred tax asset was approximately $40 million, primarily consisting of deferred tax assets related to tax attributes acquired from QEP, partially offset by a valuation allowance, 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. The acquired income tax attributes, including federal net operating loss and credit carryforwards, are subject to an annual limitation under Section 382. The Company has considered the positive and negative evidence regarding realizability of these federal tax attributes including taxable income in prior carryback years, the annual limitation imposed by Section 382, and the anticipated timing of reversal of its deferred tax liabilities, resulting in a valuation allowance of $23 million on the portion of QEP’s federal tax attributes estimated not more likely than not to be realized prior to expiration. Acquired tax attributes also include state net operating loss carryforwards for which a valuation allowance of $117 million has been provided, since the Company does not believe the state net operating losses are more likely than not to be realized based on its assessment of anticipated future operations in those states.

In addition, as of December 31, 2021, the Company had a valuation allowance of $6 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 $169 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. 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, 2021, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

At December 31, 2021, the Company's net deferred tax liabilities include deferred tax assets of approximately $6 million related to Viper's NOL carryforwards and approximately $163 million related to Viper's investment in Viper LLC. Subsequent to Viper's change in tax status, 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, 2021, Viper had federal NOL carryforwards of approximately $29 million which may be carried forward indefinitely to offset future taxable income.

As of December 31, 2021, Viper had a valuation allowance of approximately $169 million related to deferred tax assets that Viper does not believe are more likely than not to be realized. Management considers the likelihood that Viper's NOLs and other deferred tax attributes will be utilized prior to their expiration, if applicable. The determination to record a valuation allowance was based on 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. In light of those criteria for recognizing the tax benefit of deferred tax assets, the assessment resulted in application of a valuation allowance against Viper's federal deferred tax assets as of March 31, 2020 and subsequent balance sheet dates within the years ended December 31, 2020 and 2021.

As discussed further in Note 6—Rattler Midstream LP, on May 28, 2019, Rattler completed its initial public offering. Even though Rattler is organized as a limited partnership under state law, Rattler is subject to U.S. federal and state income tax at corporate rates, subsequent to the effective date of Rattler's election to be treated as a corporation for U.S. federal income tax purposes. As such, Rattler's provision for income taxes is included in the Company's consolidated financial statements and to the extent applicable, in net income attributable to the non-controlling interest.

At December 31, 2021, the Company's net deferred tax liabilities include deferred tax assets of approximately $23 million related to Rattlers NOL carryforwards and approximately $40 million related to Rattler's investment in Rattler LLC. At December 31, 2021, Rattler had federal net operating loss carryforwards of approximately $108 million which may be carried forward indefinitely to offset future taxable income.

Management considers the likelihood that Rattler's NOLs and other deferred tax attributes will be utilized prior to their expiration, if applicable. At December 31, 2021, Rattler's assessment included consideration of all available positive and negative evidence, including Rattler's projected future taxable income and the anticipated timing of reversal of deferred tax assets. As a result of the assessment, management determined that it is more likely than not that Rattler will realize its deferred tax assets as of December 31, 2021.

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

	December 31, 2021	December 31, 2020
	(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)	(5)
Total that, if recognized, would impact the effective income tax rate as of the end of the year	$ 3	$ 2

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. Energen is currently under IRS examination of its federal consolidated income tax returns for 2014 and 2016. Accordingly, 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, 2021 and 2020, there was less than $0.2 million of interest and no penalties related to each period associated with uncertain tax positions recognized in the Company’s consolidated financial statements.

15. DERIVATIVES

At December 31, 2021, the Company has commodity derivative contracts and receive-fixed, pay-variable interest rate hedges 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 has multiple commodity derivative contracts that contain 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.

As of December 31, 2021, 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	2022	Swap	1,000	WTI	$—	$45.00	$—	$—
Jan. - June	2022	Swap(1)	13,900	Brent	$—	$67.54	$—	$—
Jan. - June	2022	Basis Swap(2)	17,000	Argus WTI Midland	$0.66	$—	$—	$—
July - Dec.	2022	Basis Swap(2)	10,000	Argus WTI Midland	$0.84	$—	$—	$—
Jan. - Dec.	2022	Roll Swap	30,000	WTI	$0.65	$—	$—	$—
Jan. - Mar.	2022	Costless Collar	19,500	WTI	$—	$—	$46.28	$72.67
Jan. - Mar.	2022	Costless Collar	55,000	Brent	$—	$—	$45.55	$71.08
Jan. - Mar.	2022	Costless Collar	22,000	Argus WTI Houston	$—	$—	$45.91	$70.95
Apr. - June	2022	Costless Collar	13,000	WTI	$—	$—	$46.92	$75.00
Apr. - June	2022	Costless Collar	34,000	Brent	$—	$—	$46.47	$77.00
Apr. - June	2022	Costless Collar	26,000	Argus WTI Houston	$—	$—	$46.92	$72.78
July - Sep.	2022	Costless Collar	4,000	WTI	$—	$—	$45.00	$92.65
July - Sep.	2022	Costless Collar	11,000	Brent	$—	$—	$47.73	$78.65
July - Sep.	2022	Costless Collar	10,000	Argus WTI Houston	$—	$—	$50.00	$76.66
Oct. - Dec.	2022	Costless Collar	5,000	Brent	$—	$—	$45.00	$75.56
NATURAL GAS								
Jan. - Dec.	2022	Basis Swap(2)	230,000	Waha Hub	$(0.36)	$—	$—	$—
Jan. - Mar.	2022	Costless Collar	350,000	Henry Hub	$—	$—	$2.67	$4.76
Apr. - June	2022	Costless Collar	370,000	Henry Hub	$—	$—	$2.64	$4.89
July - Dec.	2022	Costless Collar	260,000	Henry Hub	$—	$—	$2.67	$5.40
Jan. - June	2023	Basis Swap(2)	60,000	Waha Hub	$(0.57)	$—	$—	$—
July - Dec.	2023	Basis Swap(2)	40,000	Waha Hub	$(0.60)	$—	$—	$—
Jan. - Mar.	2023	Costless Collar	80,000	Henry Hub	$—	$—	$2.75	$6.83
Apr. - Dec.	2023	Costless Collar	60,000	Henry Hub	$—	$—	$2.75	$5.72

(1) Excludes 8,250 BO/d of Brent swaptions, whereby the counterparty has the right to exercise the hedge at a weighted-average price of $68.62/Bbl in the second half of 2022.

(2) 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	Weighted Average Differential	Deferred Premium
OIL							
Jan. - Mar.	2022	Put	9,500	WTI	$47.51	$—	$1.57
Jan. - Mar.	2022	Put	14,000	Brent	$50.00	$—	$1.66
Jan. - Sep.	2022	Put	8,000	Argus WTI Houston	$50.00	$—	$1.93
Oct. - Dec.	2022	Put	6,000	Argus WTI Houston	$50.00	$—	$1.88
Apr. - June	2022	Put	8,000	WTI	$47.50	$—	$1.55
Apr. - June	2022	Put	24,000	Brent	$50.00	$—	$1.80
July - Sep.	2022	Put	20,000	Brent	$50.00	$—	$1.84
Oct. - Dec.	2022	Put	16,000	Brent	$50.00	$—	$1.84
Jan. - Dec.	2022	Basis Put	50,000	Brent	$—	$(10.40)	$0.78

Interest Rate Swaps

In the second quarter of 2021, the Company entered into two interest rate swap agreements for notional amounts of $600 million each to limit the Company's exposure to changes in the fair value of debt due to movements in LIBOR interest rates. These interest rate swaps have been designated as fair value hedges of the Company's $1.2 billion 3.50% fixed rate senior notes due 2029 (the "2029 Notes") whereby the Company will receive the fixed rate of interest and will pay an average variable rate of interest based on three month LIBOR plus 2.1865%. Gains and losses due to changes in the fair value of the interest rate swaps completely offset changes in the fair value of the hedged portion of the underlying debt, and were not material for the year ended December 31, 2021. These interest rate swaps are assumed to be perfectly effective and were determined to qualify for the shortcut method of accounting. The swaps expire on December 1, 2029, with an alternative early termination date of September 1, 2029, which mirrors the call option in the 2029 Notes.

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 16—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,		
	2021	2020	2019
	(In millions)		
Gain (loss) on derivative instruments, net:			
Commodity contracts	$ (978)	$ (32)	$ (151)
Interest rate swaps	130	(49)	43
Total	$ (848)	$ (81)	$ (108)
Net cash received (paid) on settlements:			
Commodity contracts(1)(2)	$ (1,305)	$ 250	$ 37
Interest rate swaps(3)	80	—	43
Total	$ (1,225)	$ 250	$ 80

(1) The year ended December 31, 2021 includes cash paid on commodity contracts terminated prior to their contractual maturity of $16 million.
(2) The year ended December 31, 2020 includes cash received on commodity contracts terminated prior to their contractual maturity of $17 million.
(3) The years ended December 31, 2021 and 2019 include cash received on interest rate swap contracts terminated prior to their contractual maturity of $80 million and $43 million, respectively.

16. FAIR VALUE MEASUREMENTS

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

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, 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. Interest rate swaps 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, can be derived from information available in publicly quoted markets, or are provided by financial institutions that trade these contracts. These valuations are Level 2 inputs. The net fair value of the Company's interest rate swaps designated as hedges are included in long-term debt in 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 in the Company's consolidated balance sheets as of December 31, 2021 and December 31, 2020. The net amounts of derivative instruments are classified as current or noncurrent based on their anticipated settlement dates.

	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:						
Derivative instruments	$ —	$ 60	$ —	$ 60	$ (57)	$ 3
Interest rate swaps designated as hedges	$ —	$ 10	$ —	$ 10	$ —	$ 10
Non-current:						
Derivative instruments	$ —	$ 12	$ —	$ 12	$ (8)	$ 4
Interest rate swaps designated as hedges	$ —	$ 1	$ —	$ 1	$ (1)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 231	$ —	$ 231	$ (57)	$ 174
Non-current:						
Derivative instruments	$ —	$ 9	$ —	$ 9	$ (8)	$ 1
Interest rate swaps designated as hedges	$ —	$ 29	$ —	$ 29	$ (1)	$ 28

	As of December 31, 2020					
	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:						
Derivative instruments	$ —	$ 43	$ —	$ 43	$ (42)	$ 1
Non-current:						
Derivative instruments	$ —	$ 187	$ —	$ 187	$ (187)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 291	$ —	$ 291	$ (42)	$ 249
Non-current:						
Derivative instruments	$ —	$ 244	$ —	$ 244	$ (187)	$ 57

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, 2021		December 31, 2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt	$ 6,687	$ 7,148	$ 5,815	$ 6,213

The fair values of the Company's credit agreement, the Viper credit agreement and 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, 2021 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 8—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.

17. SUPPLEMENTAL INFORMATION TO STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 194	$ 221	$ 187
Cash paid (received) for income taxes	$ (138)	$ —	$ —
Supplemental disclosure of non-cash transactions:			
Accrued capital expenditures included in accounts payable and accrued expenses	$ 287	$ 213	$ 553
Capitalized stock-based compensation	$ 20	$ 16	$ 17
Common stock issued for business combinations	$ 1,727	$ —	$ —
Asset retirement obligations acquired	$ 65	$ 2	$ 4

18. COMMITMENTS AND CONTINGENCIES

The Company is a party to various 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, 2021:

Year Ending December 31,	Transportation Commitments(1)	Sand Supply Agreement(2)	Produced Water Disposal Commitments(3)
		(In millions)	
2022	$ 82	$ 18	$ 5
2023	85	18	5
2024	81	18	5
2025	86	18	5
2026	92	5	4
Thereafter	452	—	27
Total	$ 878	$ 77	$ 51

(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) 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.

(3) Rattler entered into a minimum volume commitment to purchase produced water disposal services under a 14 year agreement beginning in 2021.

At December 31, 2021, the Company's delivery commitments covered the following gross volumes of oil:

Year Ending December 31,	Oil Volume Commitments (Bbl/d)
2022	175,000
2023	175,000
2024	125,000
2025	125,000
2026	125,000
Thereafter	325,000
Total	1,050,000

As of December 31, 2021, Rattler's anticipated future capital commitments for its equity method investments total $28 million in the aggregate. The timing of when capital commitments will be requested can vary, but at December 31, 2021, approximately $11 million of the remaining commitment is expected to be funded in 2022, with the remaining $17 million expected to be funded in 2023.

19. SUBSEQUENT EVENTS

Fourth Quarter 2021 Dividend Declaration

On February 18, 2022, the Board of Directors of the Company declared a cash dividend for the fourth quarter of 2021 of $0.60 per share of common stock, payable on March 11, 2022 to its stockholders of record at the close of business on March 4, 2022.

20. SEGMENT INFORMATION

The Company reports its operations in 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. All of the Company's equity method investments are included in the midstream operations segment. 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	Midstream Operations	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	Midstream Operations	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

	Upstream	Midstream Operations	Eliminations	Total
	(In millions)			
Year Ended December 31, 2019:				
Third-party revenues	$ 3,891	$ 73	$ —	$ 3,964
Intersegment revenues	—	375	(375)	—
Total revenues	$ 3,891	$ 448	$ (375)	$ 3,964
Depreciation, depletion, amortization and accretion	$ 1,411	$ 43	$ —	$ 1,454
Impairment of oil and natural gas properties	$ 790	$ —	$ —	$ 790
Income (loss) from operations	$ 790	$ 219	$ (314)	$ 695
Interest expense, net	$ (171)	$ (1)	$ —	$ (172)
Other income (expense)	$ (149)	$ (6)	$ (6)	$ (161)
Provision for (benefit from) income taxes	$ 21	$ 26	$ —	$ 47
Net income (loss) attributable to non-controlling interest	$ 75	$ 91	$ (91)	$ 75
Net income (loss) attributable to Diamondback Energy, Inc.	$ 374	$ 95	$ (229)	$ 240
Total assets	$ 22,125	$ 1,636	$ (230)	$ 23,531

21. 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, 2021	December 31, 2020
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 24,418	$ 19,884
Unproved properties	8,496	7,493
Total oil and natural gas properties	32,914	27,377
Accumulated depletion	(5,434)	(4,237)
Accumulated impairment	(7,954)	(7,954)
Net oil and natural gas properties capitalized	$ 19,526	$ 15,186

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, 2021	2020	2019
	(In millions)		
Acquisition costs:			
Proved properties	$ 2,805	$ 13	$ 194
Unproved properties	1,829	106	418
Development costs	516	381	956
Exploration costs	1,223	1,098	1,915
Total	$ 6,373	$ 1,598	$ 3,483

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,		
	2021	2020	2019
	(In millions)		
Oil, natural gas and natural gas liquid sales	$ 6,747	$ 2,756	$ 3,887
Production costs	(1,202)	(760)	(826)
Depreciation, depletion, amortization and accretion	(1,211)	(1,249)	(1,405)
Impairment	—	(6,021)	(790)
Income tax benefit (expense)	(918)	1,151	(186)
Results of operations	$ 3,416	$ (4,123)	$ 680

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2021, 2020 and 2019 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. 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 Liquids (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves:			
As of December 31, 2018	626,936	190,291	1,048,649
Extensions and discoveries	256,569	66,572	318,874
Revisions of previous estimates	(84,789)	(8,166)	(149,657)
Purchase of reserves in place	13,974	3,813	19,830
Divestitures	(33,269)	(3,809)	(21,272)
Production	(68,518)	(18,498)	(97,613)
As of December 31, 2019	710,903	230,203	1,118,811
Extensions and discoveries	191,009	58,410	316,035
Revisions of previous estimates	(78,244)	21,927	300,160
Purchase of reserves in place	2,124	778	3,512
Divestitures	(209)	(141)	(905)
Production	(66,182)	(21,981)	(130,549)
As of December 31, 2020	759,401	289,196	1,607,064
Extensions and discoveries	271,222	127,479	720,125
Revisions of previous estimates	(160,570)	(6,685)	195,302
Purchase of reserves in place	176,261	58,587	302,770
Divestitures	(36,503)	(11,597)	(70,048)
Production	(81,522)	(27,246)	(169,406)
As of December 31, 2021	928,289	429,734	2,585,807
Proved Developed Reserves:			
December 31, 2018	403,051	125,509	705,084
December 31, 2019	457,083	165,173	824,760
December 31, 2020	443,464	192,495	1,085,035
December 31, 2021	620,474	285,513	1,770,688
Proved Undeveloped Reserves:			
December 31, 2018	223,885	64,782	343,565
December 31, 2019	253,820	65,030	294,051
December 31, 2020	315,937	96,701	522,029
December 31, 2021	307,815	144,221	815,119

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, 2021, the Company’s extensions and discoveries of 518,722 MBOE resulted primarily from the drilling of 470 new wells, 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.

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

During the year ended December 31, 2020, the Company’s extensions and discoveries of 302,092 MBOE resulted primarily from the drilling of 682 new wells 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.

During the year ended December 31, 2019, the Company’s extensions and discoveries totaling 376,287 MBOE resulted primarily from the drilling of 283 new wells and from 291 new proved undeveloped locations added. Viper royalty interests accounted for 5% of the extension volumes. The Company’s downward revisions of 117,898 MBOE were the result of proved undeveloped downgrades associated with inventory refinement following the Energen acquisition along with updated development plans and lower realized prices. Purchases of 21,092 MBOE were the result of 10,939 MBOE of working interest purchases and 10,153 MBOE of Viper royalty purchases, excluding mineral interests dropped down to Viper.

At December 31, 2021, the Company’s estimated PUD reserves were approximately 587,889 MBOE, an 88,246 MBOE increase over the reserve estimate at December 31, 2020 of 499,643 MBOE. The following table includes the changes in PUD reserves for 2021 (MBOE):

Beginning proved undeveloped reserves at December 31, 2020	499,643
Undeveloped reserves transferred to developed	(172,526)
Revisions	(243,268)
Purchases	63,013
Divestitures	—
Extensions and discoveries	441,027
Ending proved undeveloped reserves at December 31, 2021	587,889

The increase in proved undeveloped reserves was primarily attributable to extensions of 416,327 MBOE from 439 gross (383 net) wells in which the Company has a working interest and 24,700 MBOE from 336 gross wells in which Viper owns royalty interests. Of the 439 gross working interest wells, 409 were in the Midland Basin and 30 were in the Delaware Basin. Transfers of 172,526 MBOE from undeveloped to developed reserves were the result of drilling or participating in 154 gross (142 net) horizontal wells in which the Company has a working interest and 127 gross wells in which the Company has a royalty interest or mineral interest through Viper. The Company owns a working interest in 106 of the 127 gross Viper wells. Downward revisions of 243,268 MBOE were the result of negative revisions of 260,494 MBOE due to 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 17,226 MBOE primarily attributable to higher commodity prices and improved well performance. Purchases of 63,013 MBOE were the result of 59,023 MBOE primarily from QEP and Guidon, and 3,990 MBOE of Viper royalty purchases.

As of December 31, 2021, all of the Company’s proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2021, approximately $516 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, 2021, 2020 and 2019:

	December 31, 2021	December 31, 2020	December 31, 2019
	(In millions)		
Future cash inflows	$ 77,085	$ 32,173	$ 40,681
Future development costs	(4,243)	(3,585)	(3,809)
Future production costs	(19,123)	(10,763)	(9,319)
Future production taxes	(5,572)	(2,354)	(2,905)
Future income tax expenses	(7,237)	(727)	(2,635)
Future net cash flows	40,910	14,744	22,013
10% discount to reflect timing of cash flows	(22,193)	(7,986)	(11,829)
Standardized measure of discounted future net cash flows[(1)]	$ 18,717	$ 6,758	$ 10,184

(1) Includes $2.1 billion, $1.0 billion, and $1.3 billion, for the years ended December 31, 2021, 2020 and 2019, respectively, attributable to the Company's consolidated subsidiary, Viper, in which there is a 54% non-controlling interest at December 31, 2021.

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, 2021	December 31, 2020	December 31, 2019
Oil (per Bbl)	$ 64.78	$ 38.06	$ 51.88
Natural gas (per Mcf)	$ 2.61	$ 0.09	$ 0.18
Natural gas liquids (per Bbl)	$ 23.71	$ 10.83	$ 15.65

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, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
	(In millions)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 6,758	$ 10,184	$ 11,676
Sales of oil and natural gas, net of production costs	(5,757)	(2,225)	(3,334)
Acquisitions of reserves	1,914	30	309
Divestitures of reserves	(275)	(4)	(500)
Extensions and discoveries, net of future development costs	6,298	1,514	4,004
Previously estimated development costs incurred during the period	548	704	120
Net changes in prices and production costs	10,748	(5,273)	831
Changes in estimated future development costs	(19)	526	(3,190)
Revisions of previous quantity estimates	719	(462)	(1,242)
Accretion of discount	703	1,126	1,344
Net change in income taxes	(2,841)	807	693
Net changes in timing of production and other	(79)	(169)	(527)
Standardized measure of discounted future net cash flows at the end of the period	$ 18,717	$ 6,758	$ 10,184