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 001-36505

Viper Energy Partners LP
(Exact Name of Registrant As Specified in Its Charter)

DE	**46-5001985**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas Suite 1200 Midland, TX	**79701**
(Address of principal executive offices)	**(Zip code)**

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	VNOM	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

Securities registered pursuant to section 12(g) of the Act:
None.

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

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

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

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

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

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

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

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

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

The aggregate market value of the common units held by non-affiliates was approximately $1.2 billion on June 30, 2021, the last business day of the registrant's most recently completed second fiscal quarter, based on closing prices in the daily composite list for transactions on the Nasdaq Global Select Market on such date. As of February 18, 2022, 76,966,203 common units representing limited partner interests and 90,709,946 Class B units representing limited partner interests were outstanding.

Documents Incorporated By Reference: None

VIPER ENERGY PARTNERS LP

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2021

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl or barrel	One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BO	One barrel of oil.
BO/d	BO per day.
BOE	One barrel of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
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.
Deterministic method	The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.
Developed acreage	Acreage allocated or assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Development well	A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole 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.
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	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.
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 royalty acres	Net mineral acres multiplied by the average lease royalty interest and other burdens.

Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	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.
Productive well	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
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.
Spud	Commencement of actual drilling operations.
Standardized measure	The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.
Tight formation	A formation with low permeability that produces natural gas with very low flow rates for long periods of time.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI	West Texas Intermediate.

GLOSSARY OF CERTAIN OTHER TERMS

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

ASU	Accounting Standards Update.
Delaware Act	Delaware Revised Uniform Limited Partnership Act.
Diamondback	Diamondback Energy, Inc., a Delaware corporation.
Diamondback E&P LLC	A subsidiary of Diamondback.
EPA	U.S. Environmental Protection Agency.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company; the general partner of the Partnership and a wholly-owned subsidiary of Diamondback.
IPO	The partnership’s initial public offering of common units.
LIBOR	The London interbank offered rate.
LTIP	Viper Energy Partners LP Long Term Incentive Plan.
OPEC	Organization of the Petroleum Exporting Countries.
Operating Company	Viper Energy Partners LLC, a Delaware limited liability company and a consolidated subsidiary of Viper Energy Partners LP.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
The Notes	The 5.375% Senior Notes due 2027 issued on October 16, 2019.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

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

- Changes in supply and demand levels for oil, natural gas, and natural gas liquids, and the resulting impact on the price for those commodities;
- the impact of public health crises, including epidemic or pandemic diseases 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 on our mineral and royalty acreage, or governmental orders, rules or regulations that impose production limits on such acreage;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations;
- restrictions on the use of water, including limits on the use of produced water by our operators and a moratorium on new produced water well permits recently imposed by the Texas Railroad Commission in an effort to control induced seismicity in the Permian Basin;
- significant declines in prices for oil, natural gas, or natural gas liquids, which could require recognition of significant impairment charges;
- changes in U.S. energy, environmental, monetary and trade policies;
- conditions in the capital, financial and credit markets, including the availability and pricing of capital for drilling and development by our operators and environmental and social responsibility projects undertaken by Diamondback and our other operators;
- changes in availability or cost of rigs, equipment, raw materials, supplies, oilfield services impacting our operators;
- changes in safety, health, environmental, tax, and other regulations or requirements impacting us or our operators (including those addressing air emissions, water management, or the impact of global climate change);
- security threats, including cybersecurity threats and disruptions to our business from breaches of 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 impacting our operators;
- severe weather conditions;
- acts of war or terrorist acts and the governmental or military response thereto;

- changes in the financial strength of counterparties to the credit agreement and hedging contracts of our operating subsidiary;
- changes in our credit rating; and
- other risks and factors disclosed in this report.

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

PART I

References in this Annual Report to (i) "Viper Energy Partners," "Viper," "the Partnership," "our partnership," "we," "our," "us" or like terms refer to Viper Energy Partners LP individually and collectively with its subsidiary, Viper Energy Partners LLC, as the context requires; (ii) "our General Partner" refers to Viper Energy Partners GP LLC, our General Partner and a wholly owned subsidiary of Diamondback Energy, Inc.; and (iii) the "Operating Company" or "OpCo" refers to Viper Energy Partners LLC, and (iv) "Diamondback" refers collectively to Diamondback Energy, Inc. and its subsidiaries other than the Partnership and its subsidiary.

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Overview

We are a publicly traded Delaware limited partnership formed by Diamondback to own and acquire mineral and royalty interests in oil and natural gas properties primarily in the Permian Basin. We are treated as a corporation for U.S. federal income tax purposes.

Our primary business objective is to provide an attractive return to our unitholders by focusing on business results, generating robust free cash flow, reducing debt and protecting our balance sheet, while maintaining a best-in-class cost structure. Our initial assets consisted of mineral interests in oil and natural gas properties in the Permian Basin in West Texas, substantially all of which are leased to working interest owners who bear the costs of operation and development.

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

Significant 2021 Acquisitions

On October 1, 2021, we completed the acquisition of certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC for approximately 15.25 million of our common units and approximately $225.3 million in cash, which we refer to as 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 has an effective date of August 1, 2021. We funded the cash portion of the purchase price for the Swallowtail Acquisition through a combination of cash on hand and approximately $190.0 million of borrowings under the Operating Company's revolving credit facility.

Our Properties

As of December 31, 2021, our assets consisted of mineral interests underlying 930,871 gross acres and 27,027 net royalty acres in the Permian Basin and Eagle Ford Shale. Diamondback is the operator of approximately 54% of our net royalty acreage. As of December 31, 2021, there were 9,095 wells producing on this acreage, of which Diamondback was the operator of 2,386 wells. Net production during the fourth quarter of 2021 was approximately 31,359 BOE/d and net production for the year ended December 31, 2021 averaged 28,110 BOE/d. For the years ended December 31, 2021, 2020 and 2019, royalty revenue generated from these mineral interests was $501.5 million, $247.0 million and $293.8 million, respectively.

The estimated proved oil and natural gas reserves of our assets, as of December 31, 2021, were 127,888 MBOE based on a reserve report prepared by Ryder Scott, our independent reserve engineers. Of these reserves, approximately 71% were classified as proved developed producing reserves. Proved undeveloped, or PUD, reserves included in this estimate were from 490 gross horizontal well locations. As of December 31, 2021, our proved reserves were approximately 54% oil, 22% natural gas liquids and 24% natural gas.

Our Relationship with Diamondback

As of December 31, 2021, our General Partner had a 100% general partner interest in us, and Diamondback owned 731,500 common units and beneficially owned all of our 90,709,946 outstanding Class B units, representing approximately 54% of our total units outstanding. Diamondback also owns and controls our General Partner. We believe that the properties held by Diamondback include properties that have, or with additional development will have, production and reserves characteristics that could make them attractive for inclusion in our partnership. We believe Diamondback's significant ownership in us will motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so and may elect to dispose of mineral and other interests in such properties without offering us the opportunities to acquire them.

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

In addition, neither we, the Operating Company nor our General Partner has any employees. Diamondback provides management, operating and administrative services to us and our General Partner. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this report.

Business Strategies

Our primary business objective is to provide an attractive return to unitholders by focusing on business results, generating robust free cash flow, reducing debt and protecting our balance sheet, while maintaining a best-in-class cost structure. We intend to accomplish this objective by executing the following strategies:

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

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

- ***Seek to acquire from Diamondback, from time to time, mineral or other interests in producing oil and natural gas properties that meet our acquisition criteria***. Since our formation, we have acquired, and may have additional opportunities from time to time in the future to acquire, mineral or other interests in producing oil and natural gas properties directly from Diamondback. We believe Diamondback may be incentivized to sell properties to us, as doing so may enhance Diamondback's economic returns by monetizing long-lived producing properties while potentially retaining a portion of the resulting cash flow through distributions on Diamondback's limited partner interests in us. However, none of Diamondback or any of its affiliates is contractually obligated to offer or sell any interests in properties to us.

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

- ***Maintain a conservative capital structure to allow financial flexibility.*** Since our formation, we have maintained a conservative capital structure that has allowed us to opportunistically purchase accretive mineral and other interests. We are committed to maintaining a conservative leverage profile, and will continue to seek to opportunistically fund accretive acquisitions. We intend to continue to repay debt using free cash flow to ensure our ability to successfully operate in challenging business and commodity price environments.

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

Competitive Strengths

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

- ***Oil rich resource base in one of North America's leading resource plays***. The majority of the acreage underlying our mineral interests is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. As of December 31, 2021, 293 horizontal drilling rigs were operating in the Permian Basin, representing 50% of the total U.S. onshore horizontal rig activity. The majority of our current properties is well positioned in the core of both the Midland and Delaware Basins. Production on our properties for the year ended December 31, 2021 and our estimated net proved reserves are heavily oil-weighted.

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

- ***Experienced and proven management team***. The members of our executive team have significant industry experience, most of which has been focused on resource play development in the Permian Basin. This 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 property acquisition. We expect to benefit from the industry relationships of the management team. We believe the experience of our management team is essential for the execution of our business strategy.

- ***Favorable and stable operating environment.*** We primarily focus our growth in the Permian Basin, one of the oldest, most prolific hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With over 350,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with fewer operational risks, in the Permian Basin as compared to emerging hydrocarbon basins. We believe that the impact of the proven application of new technology, combined with the substantial geological information available about the Permian Basin, also reduces the risk of development and exploration activities as compared to emerging hydrocarbon basins.

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, 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, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible–from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations–prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 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 90% 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 10% 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, our petroleum engineers and geoscience professionals work 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 report 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 gas production, well test data, commodity prices and operating and development costs. Prior to his retirement effective December 31, 2021, the Executive Vice President and Chief Engineer of our General Partner was primarily responsible for overseeing the preparation of all of our reserve estimates. Effective January 1, 2022, the Senior Vice President of Reservoir Engineering of our General Partner 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 years 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 our operators;
- preparation of reserve estimates by the primary reserve engineers of our General Partner 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 the Executive Vice President and Chief Engineer, prior to his retirement, to the Chief Executive Officer of our General Partner and by the current primary reserve engineer to the President of our General Partner;
- 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 based on the reserve reports prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

	December 31,		
	2021	2020	2019
Estimated proved developed reserves:			
Oil (MBbls)	49,280	40,220	40,857
Natural gas (MMcf)	134,485	93,617	80,737
Natural gas liquids (MBbls)	19,476	16,724	14,994
Total (MBOE)	91,170	72,547	69,307
Estimated proved undeveloped reserves:			
Oil (MBbls)	19,960	17,310	13,563
Natural gas (MMcf)	49,205	25,833	15,037
Natural gas liquids (MBbls)	8,557	5,229	3,570
Total (MBOE)	36,718	26,845	19,639
Estimated net proved reserves:			
Oil (MBbls)	69,240	57,530	54,420
Natural gas (MMcf)	183,690	119,450	95,774
Natural gas liquids (MBbls)	28,033	21,953	18,564
Total (MBOE)[(1)]	127,888	99,392	88,946
Percent proved developed	71 %	73 %	78 %

(1) Estimates of reserves as of December 31, 2021, 2020 and 2019 were prepared using 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. 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 14—Supplemental Information on Oil and Natural Gas Operations for further discussion of our reserve estimates and pricing.

Proved Undeveloped Reserves

As of December 31, 2021, our PUD reserves totaled 19,960 MBbls of oil, 49,205 MMcf of natural gas and 8,557 MBbls of natural gas liquids, for a total of 36,718 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Our PUD reserves were from 490 horizontal wells, of which Diamondback is the operator of 473 wells with ConocoPhillips operating the majority of the remaining wells. Of the horizontal locations, 147 are Wolfcamp A wells, 131 are Lower Spraberry wells, 102 are Wolfcamp B wells, 100 are Middle Spraberry/Jo Mill wells and 10 are Bone Spring wells.

The following table includes the changes in PUD reserves for 2021:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2020	26,845
Undeveloped reserves transferred to developed	(8,349)
Revisions	(10,468)
Purchases	3,990
Extensions and discoveries	24,700
Ending proved undeveloped reserves at December 31, 2021	36,718

The increase in proved undeveloped reserves was primarily attributable to additions of 24,700 MBOE, primarily from 336 horizontal well locations attributable to extensions resulting from strategic drilling of wells to delineate our acreage position and acquisitions of 3,990 MBOE, partially offset by the conversion of PUD reserves into proved developed reserves of 8,349 MBOE. Downward revisions of 10,468 MBOE were primarily attributable to PUD downgrades of 11,263 MBOE, which were partially offset by other positive revisions.

All of our PUD drilling locations are scheduled to be drilled within five years from the date they were initially recorded. As of December 31, 2021, none of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

We operate in the Permian Basin and the Eagle Ford Shale in Texas in one reportable segment engaged in the acquisition of oil and natural gas properties. At December 31, 2021, 2020 and 2019, the Permian Basin contained 15% or more of our total proved reserves. The following table sets forth information regarding our share of our operators' net production of oil, natural gas and natural gas liquids, for these fields along with our share of our operators' net production from fields containing less than 15% of our total proved reserves:

	Permian Basin	Other(1)	Total
Production Data:			
Year Ended December 31, 2021			
Oil (MBbls)	5,950	118	6,068
Natural gas (MMcf)	13,326	346	13,672
Natural gas liquids (MBbl)	1,841	72	1,913
Combined volumes (MBOE)	10,012	248	10,260
Year Ended December 31, 2020			
Oil (MBbls)	5,800	156	5,956
Natural gas (MMcf)	11,098	388	11,486
Natural gas liquids (MBbl)	1,763	85	1,848
Combined volumes (MBOE)	9,413	306	9,718
Year Ended December 31, 2019			
Oil (MBbls)	4,890	233	5,123
Natural gas (MMcf)	7,029	628	7,657
Natural gas liquids (MBbl)	1,339	120	1,459
Combined volumes (MBOE)	7,401	458	7,858

(1) Production data for the year ended December 31, 2021, 2020 and 2019 includes the Eagle Ford Shale.

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)	$ 65.51	$ 36.58	$ 51.61
Natural gas (per Mcf)	$ 3.60	$ 0.79	$ 1.06
Natural gas liquids (per Bbl)	$ 28.66	$ 10.88	$ 14.63
Combined (per BOE)	$ 48.88	$ 25.41	$ 37.39
Oil, hedged ($/Bbl)[(1)]	$ 50.25	$ 32.00	$ 51.61
Natural gas, hedged ($/Mcf)[(1)]	$ 3.60	$ 0.02	$ 1.06
Natural gas liquids ($/Bbl)[(1)]	$ 28.66	$ 10.88	$ 14.63
Combined price, hedged ($/BOE)[(1)]	$ 39.86	$ 21.71	$ 37.39

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

Productive Wells

As of December 31, 2021, we owned an average 3.3% net revenue interest in 9,095 gross productive wells, including an average 3.4% net revenue interest in 8,781 gross oil productive wells and an average 1.7% net revenue interest in 314 gross natural gas productive wells. As of December 31, 2021, we had 18 gross wells with an average 4.8% net revenue interest in process of being drilled by Diamondback. The expected timing of these wells is based primarily on permitting by third party operators or Diamondback's current expected completion schedule. Productive wells consist of producing wells capable of production, including natural gas awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest.

Acreage

The following table sets forth information as of December 31, 2021 relating to the gross and net royalty acreage of our mineral interests:

Basin	Gross Royalty Acreage	Net Royalty Acreage
Delaware	497,473	15,008
Midland	309,977	11,338
Eagle Ford Shale	123,421	681
Total acreage	930,871	27,027

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

Title to Properties

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

Competition

The oil and natural gas industry is intensely competitive, and 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.

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

Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions such as the severe winter storms in the Permian Basin in early 2021, and lease stipulations can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for our operators in meeting well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Regulation

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

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

Environmental Matters

Oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations.

Liability under such laws and regulations is often strict (i.e., no showing of "fault" is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our business and prospects.

Waste Handling

The Resource Conservation and Recovery Act, or the RCRA, as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under the RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent non-hazardous waste requirements. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in the U.S. Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and natural gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and natural gas waste 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. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase the costs to manage and dispose of 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.

Air Emissions

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

Climate Change

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

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

Other Regulation of the Oil and Natural Gas Industry

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

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

Drilling and Production

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

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

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

Natural Gas Sales and Transportation

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

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that our operators produce, as well as the revenues our operators receive for sales of natural gas and release of natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities. Under FERC’s current regulatory regime, transmission services are provided on an open-access, non-discriminatory basis at cost-based rates or negotiated rates. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our operators’ costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation

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

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

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

State Regulation

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

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

Employees

We do not have any employees. We are managed and operated by the board of directors and executive officers of our General Partner. All of the individuals that conduct our business, including our executive officers, are employed by Diamondback.

Facilities

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

Availability of Partnership 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.viperenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 1A. RISK FACTORS

*Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks were to occur, our business, financial condition, results of operations and cash available for distribution could be materially adversely affected. In that case, we might not be able to make distributions on our common units, the trading price of our common units could decline, and unitholders could lose all or part of their investment. Other risks are also described in "**Items 1 and 2. Business and Properties**," "**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**" and "**Item 7A. Quantitative and Qualitative Disclosures About Market Risk**."*

Risks Related to Our Business

Our business has been and could continue to be adversely affected by the ongoing COVID-19 pandemic and volatility in the oil and natural gas markets.

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 have been 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, continued to contribute 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 2021) of gradual monthly output increases in February 2022, raising its output target by 400,000 Bbl 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, Diamondback and certain of our other operators have kept production on our acreage relatively flat during 2021, using excess cash flow for debt repayment and/or return to their stockholders rather than expanding their drilling programs. Diamondback also indicated that it intends to continue exercising capital discipline and maintaining its fourth quarter 2021 oil production flat in 2022. We cannot reasonably predict whether production levels will remain at current levels or the impact the full extent of the events above and 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. Lower oil and natural gas prices may also result in a reduction in the borrowing base under the Operating Company's revolving credit facility, which may be determined at the discretion of our lenders.

Other significant factors that are likely to continue to affect commodity prices in future periods include, but are not limited to, actions by OPEC members and other oil exporting nations, the effect of U.S. energy, monetary and trade policies, U.S. and global economic conditions, U.S. and global political and economic developments, including the Biden Administration's energy and environmental policies, the impact of the ongoing COVID-19 pandemic on conditions in the U.S. oil and natural gas industry and the potential impact of any Russian-Ukrainian conflict on the global energy markets, all of which are beyond our control. Our business may be also adversely impacted by any future government rule, regulation or order that may impose production limits, as well as pipeline capacity and storage constraints, in the Permian Basin or Eagle Ford Shale where we have mineral and royalty interests. We cannot predict the ultimate impact of these factors on our business, financial condition and cash available for distribution to our unitholders.

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 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.

Increased costs of capital could adversely affect our business.

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

We may not have sufficient available cash to pay any quarterly distribution on our common units, our cash available for distribution may vary significantly from quarter to quarter and the board of directors of our General Partner has recently modified, and may in the future further modify or revoke, our cash distribution policy at any time at its discretion. Our distribution policy could limit our ability to grow and make acquisitions.

We may not have sufficient available cash each quarter to enable us to pay any distributions to our common unitholders. Furthermore, our partnership agreement does not require us to pay distributions on a quarterly basis or otherwise. The amount of cash we have to distribute each quarter principally depends primarily upon the amount of royalty income we generate, which are dependent upon the volumes of production sold and the prices that our operators realize from the sale of such production. In addition, the actual amount of cash we will have to distribute each quarter under our cash distribution policy will be reduced by replacement capital expenditures, payments in respect of debt service and other contractual obligations and fixed charges and increases in reserves for future operating or capital needs that the board of directors may determine is appropriate. During 2020, our General Partner made certain modifications to our distribution policy that reduced the distribution amount and made additional modifications in 2021 to increase the distribution amount. Our General Partner may further modify or revoke our distribution policy at any time in the future at its discretion. For information regarding our distribution policy and the recent modifications, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." As a result, quarterly distributions paid to our unitholders may vary significantly from quarter to quarter and may be zero.

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

To the extent we issue additional units in connection with any acquisitions or growth capital expenditures or as in-kind distributions, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units.

We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk.

We use fixed price swap contracts, fixed price basis swap contracts and costless collar contracts with corresponding put and call options to reduce price volatility associated with certain of our royalty income. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing (Cushing and Midland-Cushing) and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub and Waha Hub pricing. By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk and market risk due to 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 us, which creates credit risk. Our counterparties have been determined to have an acceptable credit risk; therefore, we do not require collateral from our counterparties. By using derivative instruments, we also may not realize the benefit of any short-term increase in the price of oil and natural gas.

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

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

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

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

Approximately 29% 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 operations by the operators on our mineral and royalty acreage. 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, complete and develop such reserves, or further decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Our future 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 successful exploration or development activities are conducted on our properties or we acquire properties containing proved reserves, or both. To increase reserves and production, we would need to undertake development, exploration and other replacement activities or use third parties to accomplish these activities. Substantial capital expenditures will be necessary for the development, production, exploration and acquisition of oil and natural gas reserves. Neither we nor our third party operators may have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and efforts to drill productive wells at low finding and development costs may be unsuccessful. In addition, we do not expect to retain cash from our operations for replacement capital expenditures. Furthermore, although our revenues and cash available for distribution may increase if prevailing oil and natural gas prices increase significantly, finding costs for additional reserves could also increase.

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

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

Our producing properties are primarily 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 electric 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, all of our proved reserves were attributable to the Midland and Delaware basins and the Eagle Ford Shale. 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.

Our failure to successfully identify, complete and integrate acquisitions of properties or businesses could slow our growth and adversely affect our results of operations and cash available for distribution.

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. Unless our operators further develop our existing properties, we will depend on acquisitions to grow our reserves, production and cash flow.

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. Further, these acquisitions may be in geographic regions in which we do not currently hold properties. If we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements and other unforeseen difficulties. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to 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.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations and cash available for distribution. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations and cash available for distribution.

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

When acquiring oil and natural gas leases, we may not elect to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we may 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 an interest worthless and can adversely affect our results of operations, financial condition and cash available for distribution.

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

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

Our method of accounting for investments in oil and natural gas properties may result in impairments in future periods.

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. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs are amortized over total proved reserves.

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

No impairments of proved oil and natural gas properties were recorded for the years ended December 31, 2021 and 2019. We recorded impairment expense of $69.2 million for the year ended December 31, 2020. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates—Method of Accounting for Oil and Natural Gas Properties." If the prices of oil and natural gas continue to decline, we may be required to further write-down the value of our oil and natural gas properties in the future, which could negatively affect our results of operations.

Our estimated reserves 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. 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.

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

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

Changes in environmental laws could increase our operators' 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 or our operators' business. However, such actions could significantly increase our operators' costs or impair their ability to explore and develop other projects, which could adversely impact our business, financial condition and cash flows.

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

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

We are subject to 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, including 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 energy assets might be specific targets of cyber security threats. Our and our operators' technologies, systems, networks, and those of 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 business activities. 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 business, financial condition and cash flows.

Risks Related to Our Indebtedness

We have in the past, and we expect in the future to incur borrowings under the Operating Company's revolving credit facility. Unless we are able to repay borrowings under the revolving credit facility with cash flow from operations and proceeds from equity offerings, implementing our capital programs may require an increase in our total leverage through additional debt issuances. In addition, a reduction in availability under the revolving credit facility and the inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.

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

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

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

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

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

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

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

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

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

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

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

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

Our earnings are exposed to interest rate risk associated with borrowings under the Operating Company's revolving credit facility which provides for interest on borrowings at a floating rate equal to, an alternative 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 rate increases in 2022, and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. We have not hedged our interest rate exposure with respect to our floating rate debt. Accordingly, our interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. 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 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 Inherent in an Investment in Us

Diamondback owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations. Our General Partner and its affiliates, including Diamondback, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our unitholders.

Diamondback owns and controls our General Partner and appoints all of the directors of our General Partner. All of the executive officers and certain of the directors of our General Partner are also officers and/or directors of Diamondback. Although our General Partner has a duty to manage us in a manner that it believes is not adverse to our interest, the executive officers and directors of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to Diamondback. Therefore, conflicts of interest may arise between Diamondback or any of its affiliates, including our General Partner, on the one hand, and us or any of our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others. Our General Partner is allowed to take into account the interests of parties other than us, such as Diamondback, in exercising certain rights under our partnership agreement. Neither our partnership agreement nor any other agreement requires Diamondback to pursue a business strategy that favors us. Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing its duties, limits our General Partner's liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty. Except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval. Our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders. Our General Partner determines which costs incurred by it and its affiliates are reimbursable by us. Our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf. Our General Partner intends to limit its liability regarding our contractual and other obligations. Our General Partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units. Our General Partner controls the enforcement of obligations that it and its affiliates owe to us. Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us. In addition, Diamondback or its affiliates, may compete with us.

Neither we nor our General Partner have any employees, and we rely solely on the employees of Diamondback to manage our business. The management team of Diamondback, which includes the individuals who manage us, also perform similar services for Diamondback and certain of its affiliates, and thus are not solely focused on our business.

Neither we nor our General Partner have any employees and we rely solely on Diamondback to operate our assets and perform other management, administrative and operating services for us and our General Partner. Diamondback provides similar activities with respect to its own assets and operations and those of certain of its affiliates. Because Diamondback provides services to us that are similar to those performed for itself and its affiliates, Diamondback may not have sufficient human, technical and other resources to provide those services at a level that Diamondback would be able to provide to us if it were solely focused on our business and operations. Diamondback may make internal decisions on how to allocate its available resources and expertise that may not always be in our best interest compared to Diamondback's interests. There is no requirement that Diamondback favor us over itself or others in providing its services. If the employees of Diamondback and their affiliates do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced. Many key responsibilities within our business have been assigned to a small number of individuals. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of the executive team of our General Partner, including the Chief Executive Officer, President and Chief Financial Officer of our General Partner, Travis D. Stice, Kaes Van't Hof and Teresa L. Dick, respectively, could disrupt our business. Further, we do not maintain "key person" life insurance policies on any of our executive team or other key personnel. As a result, we are not insured against any losses resulting from the death of these key individuals.

Our partnership agreement replaces our General Partner's fiduciary duties to our unitholders.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include; how to allocate business opportunities among us and its affiliates, whether to exercise its call right, how to exercise its voting rights with respect to the units it owns, whether to exercise its registration rights and whether or not to consent to any merger or consolidation of the partnership or any amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our units for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that (i) whenever our General Partner makes a determination or takes, or declines to take, any other action in its capacity as our General Partner, our General Partner is generally required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any higher standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity, (ii) our General Partner and its executive officers and directors will not be liable for monetary damages or otherwise to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of conduct in which our General Partner or its executive officers or directors engaged in bad faith, willful misconduct or fraud or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and (iii) our General Partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction, even a transaction with an affiliate or the resolution of a conflict of interest, is (a) approved by the conflicts committee of the board of directors of our General Partner, although our General Partner is not obligated to seek such approval or (b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, other than one where our General Partner is permitted to act in its sole discretion, any determination by our General Partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors of our General

Partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Diamondback and other affiliates of our General Partner may compete with us.

Our partnership agreement provides that our General Partner is restricted from engaging in any business activities other than acting as our General Partner, engaging in activities incidental to its ownership interest in us and providing management, advisory and administrative services to its affiliates or to other persons. However, affiliates of our General Partner, including Diamondback, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Diamondback may compete with us for investment opportunities and may own an interest in entities that compete with us. Further, Diamondback and its affiliates, may acquire, develop or dispose of additional oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets.

Diamondback is an established participant in the oil and natural gas industry and has resources greater than ours, which factors may make it more difficult for us to compete with Diamondback with respect to commercial activities as well as for potential acquisitions. As a result, competition from Diamondback and its affiliates could adversely impact our results of operations and cash available for distribution to our common unitholders.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our General Partner or any of its affiliates, including its executive officers and directors, and Diamondback. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our General Partner and result in less than favorable treatment of us and our unitholders.

Holders of our units have limited voting rights and are not entitled to elect our General Partner or its directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner, including the independent directors, is chosen entirely by Diamondback, as a result of it owning our General Partner, and not by our unitholders. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our units are dissatisfied, they cannot initially remove our General Partner without its consent.

If our unitholders are dissatisfied with the performance of our General Partner, they have limited ability to remove our General Partner. Unitholders will be unable to remove our General Partner without its consent because affiliates of our General Partner own sufficient units to be able to prevent its removal. The vote of the holders of at least $66\,^2/_3\%$ of all outstanding units, voting as a single class, is required to remove our General Partner.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our units (other than our General Partner and its affiliates and permitted transferees).

Our partnership agreement restricts unitholders’ voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, may not vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our unitholders to influence the manner or direction of management.

Cost reimbursements due to our General Partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our common unitholders. There is no limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. The amount and timing of such reimbursements will be determined by our General Partner.

Prior to making any distribution to its unitholders, including us, the Operating Company will reimburse our General Partner and its affiliates for all expenses they incur and payments they make on our behalf. There is no limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed, and the amounts may be substantial. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Our General Partner will determine the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our General Partner and its affiliates will reduce the amount of cash available for distribution from the Operating Company to us and from us to our common unitholders.

In addition, we have entered into a tax sharing agreement with Diamondback pursuant to which we are required to reimburse Diamondback for our share of state and local income and other taxes borne by Diamondback as a result of our results being included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on the closing date of our IPO.

Our General Partner interest or the control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its General Partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owner of our General Partner to transfer its membership interests in our General Partner to a third party. After any such transfer, the new member or members of our General Partner would then be in a position to replace the board of directors and executive officers of our General Partner with its own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our General Partner. This effectively permits a “change of control” without the vote or consent of the unitholders.

Common unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Revised Uniform Limited Partnership Act, or the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware, to the same extent as our General Partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our General Partner if a limited partner were to lose limited liability through any fault of our General Partner.

Our General Partner has a call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our General Partner and its affiliates (including Diamondback) own more than 80% of the units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (i) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (ii) the highest per-unit price paid by our General Partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our General Partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our General Partner from causing us to issue additional common units and then exercising its call right. If our General Partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

The common units and Class B units are considered limited partner interests of a single class for these provisions. As of December 31, 2021, Diamondback owned approximately 54% of our total units outstanding.

We may issue additional common units and other equity interests without unitholder approval, which would dilute existing unitholder ownership interests.

Under our partnership agreement, we are authorized to issue an unlimited number of additional interests, including common units, without a vote of the unitholders. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects; the proportionate ownership interest of unitholders in us immediately prior to the issuance will decrease, the amount of cash distributions on each common unit may decrease, the ratio of our taxable income to distributions may increase, the relative voting strength of each previously outstanding common unit may be diminished, and the market price of the common units may decline.

There are no limitations in our partnership agreement on our ability to issue units ranking senior to the common units.

In accordance with Delaware law and the provisions of our partnership agreement, we may issue additional partnership interests that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of units of senior rank may (i) reduce or eliminate the amount of cash available for distribution to our common unitholders; (ii) diminish the relative voting strength of the total common units outstanding as a class; or (iii) subordinate the claims of the common unitholders to our assets in the event of our liquidation.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets.

Sales by holders of a substantial number of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. In addition, we have provided registration rights to Diamondback. Pursuant to these registration rights, we have registered, under the Securities Act, all of the common units owned by Diamondback for resale (including common units issuable in respect of the Class B units and the OpCo units). Under our partnership agreement, our General Partner and its affiliates have registration rights relating to the offer and sale of any common units that they hold.

Nasdaq does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the Nasdaq Global Select Market. Because we are a publicly traded partnership, Nasdaq does not require us to have a majority of independent directors on our General Partner’s board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of Nasdaq’s corporate governance requirements.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful action.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue for most claims, suits, actions and proceedings involving us or our officers, directors and employees. In addition, if any person brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys’ fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts.

Our General Partner may amend our partnership agreement, as it determines necessary or advisable, to permit the General Partner to redeem the units of certain unitholders.

Our General Partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our General Partner to redeem the units held by any person (i) whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates chargeable to our customers, (ii) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (iii) who fails to comply with the procedures established to obtain such proof. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

We ***are treated as a corporation for U.S. federal income tax purposes and our cash available for distribution to our common unitholders may be substantially reduced.***

We are a Delaware limited partnership that since May 10, 2018, has elected to be treated as a corporation for U.S. federal income tax purposes. As a result, we are subject to tax as a corporation at the corporate tax rate of 21%. While our taxable income may be reduced over the remaining period of our agreement with Diamondback to specially allocate to Diamondback priority allocations of the Operating Company's income and gains over losses and deductions (but before depletion), there is no guarantee that we will not have any taxable income as a result of our equity interests in the Operating Company. Because an entity-level tax is imposed on us due to our status as a corporation for U.S. federal income tax purposes, our distributable cash flow may be substantially reduced by our tax liabilities.

Distributions to common unitholders may be taxable as dividends.

Because we are treated as a corporation for U.S. federal income tax purposes, if we make distributions to our common unitholders from current or accumulated earnings and profits as computed for U.S. federal income tax purposes, such distributions will be treated as distributions on corporate stock for U.S. federal income tax purposes, and generally be taxable to our common unitholders as ordinary dividend income for U.S. federal income tax purposes (to the extent of our current and accumulated earnings and profits). Such dividend distributions paid to non-corporate U.S. unitholders will be subject to U.S. federal income tax at preferential rates, provided that certain holding period and other requirements are satisfied. Any portion of our distributions to common unitholders that exceeds our current and accumulated earnings and profits as computed for U.S. federal income tax purposes will constitute a non-taxable return of capital distribution to the extent of a unitholder's basis in its common units, and thereafter as gain on the sale or exchange of such common units.

Future U.S. tax legislations 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Note 12—Commitments and Contingencies of the 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 UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Listing and Holders of Record

Our common units are listed on the Nasdaq Global Select Market under the symbol "VNOM." There were 13 holders of record of our common units on February 18, 2022.

Cash Distribution Policy

Beginning with the first quarter of 2020, the board of directors of our General Partner revised the distribution policy to provide that the Operating Company would distribute a percentage of its available cash. We in turn distribute all of the available cash we receive from the Operating Company to our common unitholders. Our available cash, and the available cash of the Operating Company, for each quarter is determined by the board of directors of our General Partner following the end of such quarter. The Operating Company's available cash generally equals our Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations, fixed charges and reserves for future operating or capital needs that the board of directors of our General Partner deems necessary or appropriate, if any. Our available cash for each quarter generally equals our Adjusted EBITDA (which is our proportional share of the available cash of the Operating Company for the quarter), less cash needed for the payment of income taxes by us, if any, and the preferred distribution.

We do not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time. The board of directors of our General Partner may change our distribution policy at any time. Our partnership agreement does not require us to pay distributions to our common unitholders on a quarterly or other basis.

Repurchases of Equity Securities

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

Period	Total Number of Units Purchased	Average Price Paid Per Unit(1)	Total Number of Units Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Units that May Yet Be Purchased Under the Plan(2)
	(In thousands, except unit amounts)			
October 1, 2021 - October 31, 2021	—	$ —	—	$ 42,412
November 1, 2021 - November 30, 2021	150,000	$ 22.63	150,000	$ 89,018
December 1, 2021 - December 31, 2021	424,200	$ 21.32	424,200	$ 79,975
Total	574,200	$ 21.66	574,200	

(1) The average price paid per common unit includes any commissions paid to repurchase a common unit.
(2) The board of directors of our General Partner initially approved a $100.0 million common unit repurchase program in November of 2020 and, effective November 15, 2021, increased our authorization under this program to acquire up to $150.0 million of our outstanding common units and extended the term of the repurchase program indefinitely. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors of our General Partner at any time.

Recent Sales of Unregistered Securities

None.

ITEM 6. [RESERVED]

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto presented in 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 a publicly traded Delaware limited partnership formed by Diamondback to own and acquire mineral and royalty interests in oil and natural gas properties primarily in the Permian Basin. We operate in one reportable segment.

As of December 31, 2021, our General Partner held a 100% General Partner interest in us, and Diamondback, either directly or through one of its subsidiaries, owned 731,500 common units and beneficially owned all of our 90,709,946 outstanding Class B units, representing approximately 54% of our total units outstanding. Diamondback also owns and controls our General Partner.

The following discussion includes a comparison of our results of operations, including changes in our operating income, and liquidity and capital resources for fiscal year 2021 and fiscal year 2020. A discussion of changes in our results of operations from fiscal year 2019 to fiscal year 2020 has been omitted from this report, but may be found in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2020, filed with the SEC on February 25, 2021, and is incorporated by reference in this report from such prior Annual Report on Form 10-K.

2021 Transactions and Recent Developments

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, continued to contribute 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 2021) of gradual monthly output increases in February 2022, raising its output target by 400,000 Bbl 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.

Although demand for oil and natural gas and commodity prices have recently increased, Diamondback and certain of our other operators have kept production on our acreage relatively flat during 2021, using excess cash flow for debt repayment and/or return to their stockholders rather than expanding their drilling programs. Diamondback also indicated that it intends to continue exercising capital discipline and seeks to maintain its fourth quarter 2021 exit oil production flat in 2022. We cannot reasonably predict whether production levels will remain at current levels or the impact the full extent of the events above and subsequent recovery may have on our industry and our business.

Due to the improved commodity prices and industry conditions, based on the results of the quarterly ceiling tests, we were not required to record an impairment on our proved oil and natural gas interests during the year ended December 31, 2021. If commodity prices fall below current levels, we may be required to record impairments in future periods and such impairments could be material. Further, if commodity prices decrease, our production, proved reserves and cash flows may be adversely impacted. Our business may also be adversely impacted by any pipeline capacity and storage constraints.

Acquisitions and Divestitures Update

Swallowtail Acquisition

On October 1, 2021, we completed the Swallowtail Acquisition for approximately 15.25 million of our common units and approximately $225.3 million in cash. The mineral and royalty interests acquired represent approximately 2,313 net royalty acres primarily in the Northern Midland Basin, of which approximately 62% are operated by Diamondback. We funded the cash portion of the purchase price for the Swallowtail Acquisition through a combination of cash on hand and approximately $190.0 million of borrowings under the Operating Company's revolving credit facility. The Swallowtail Acquisition has an effective date of August 1, 2021.

Other 2021 Acquisitions

Additionally during the year ended December 31, 2021, we acquired, from unrelated third party sellers, mineral and royalty interests representing 1,277 gross (392 net royalty) acres in the Permian Basin for an aggregate purchase price of approximately $55.1 million, after post-closing adjustments. We funded these acquisitions with cash on hand and borrowings under the Operating Company's revolving credit facility.

As a result of the Swallowtail Acquisition and other acquisitions, our footprint of mineral and royalty interests increased to a total of 27,027 net royalty acres at December 31, 2021.

Divestiture

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

Cash Distribution Update

On February 16, 2022, the board of directors of our General Partner declared a cash distribution for the three months ended December 31, 2021 of $0.47 per common unit, maintaining our distribution from the second quarter of 2021 of 70% of cash available for distribution. The distribution is payable on March 11, 2022 to eligible common unitholders of record at the close of business on March 4, 2022. We expect to continue to generate robust amounts of free cash flow and subsequently use that cash to both reduce debt and increase our return on capital to unitholders.

Production and Operational Update

Our business has rebounded strongly from the unprecedented volatility experienced throughout 2020 as commodity prices have increased and activity has returned to our acreage. There are currently 39 rigs operating on our mineral and royalty acreage, six of which are operated by Diamondback. Looking ahead, with minimal capital requirements and limited operating costs, royalty companies are expected to have an advantage in 2022 and not face inflationary cost pressures. As our defensive hedges placed in 2020 rolled off at the end of 2021, our industry leading cash margins will now be further enhanced by strength in commodity prices. Our production and free cash flow outlook is expected to be driven by Diamondback's continued focus on developing our acreage, as well as our exposure to other well-capitalized operators in the Permian Basin. We continue to have a high level of visibility into Diamondback's expected forward development plan and expect additional upside from third-party operators that continue to exceed our conservative activity and timing assumptions, all of which is expected to bolster oil production for us not only for the next several quarters, but in the coming years.

The following table summarizes our gross well information as of the dates indicated:

	Diamondback Operated	Third Party Operated	Total
Horizontal wells turned to production (fourth quarter 2021)[(1)]:			
Gross wells	40	139	179
Net 100% royalty interest wells	3.7	1.4	5.1
Average percent net royalty interest	9.3 %	1.0 %	2.9 %
Horizontal wells turned to production (year ended December 31, 2021)[(2)]:			
Gross wells	158	562	720
Net 100% royalty interest wells	10.2	3.8	14.0
Average percent net royalty interest	6.5 %	0.7 %	1.9 %
Horizontal producing well count (fourth quarter 2021):			
Gross wells	1,335	4,371	5,706
Net 100% royalty interest wells	101.8	59.4	161.2
Average percent net royalty interest	7.6 %	1.4 %	2.8 %
Horizontal active development well count (as of January 27, 2022)[(3)]:			
Gross wells	106	512	618
Net 100% royalty interest wells	6.8	3.8	10.6
Average percent net royalty interest	6.4 %	0.7 %	1.7 %
Line of sight wells (as of January 27, 2022)[(4)]:			
Gross wells	135	428	563
Net 100% royalty interest wells	7.8	3.8	11.6
Average percent net royalty interest	5.8 %	0.9 %	2.1 %

(1) Average lateral length of 10,048.
(2) Average lateral length of 9,823.
(3) The total 618 gross wells currently in the process of active development are those wells that have been spud and are expected to be turned to production within approximately the next six to eight months.
(4) The total 563 line-of-sight wells are those that are not currently in the process of active development, but for which Viper has reason to believe that they will be turned to production within approximately the next 15 to 18 months. The expected timing of these line-of-sight wells is based primarily on permitting by third party operators or Diamondback's current expected completion schedule. Existing permits or active development of our net royalty acreage does not ensure that those wells will be turned to production given the volatility in oil prices.

Results of Operations

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

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(In thousands)	
Operating income:		
Oil income	$ 397,513	$ 217,859
Natural gas income	49,197	9,024
Natural gas liquids income	54,824	20,098
Royalty income	501,534	246,981
Lease bonus income	2,763	2,585
Other operating income	620	1,060
Total operating income	504,917	250,626
Costs and expenses:		
Production and ad valorem taxes	32,558	19,844
Depletion	102,987	100,501
Impairment	—	69,202
General and administrative expenses	7,800	8,165
Total costs and expenses	143,345	197,712
Income (loss) from operations	361,572	52,914
Other income (expense):		
Interest expense, net	(34,044)	(33,000)
Gain (loss) on derivative instruments, net	(69,409)	(63,591)
Gain (loss) on revaluation of investment	—	(8,556)
Other income, net	79	1,286
Total other expense, net	(103,374)	(103,861)
Income (loss) before income taxes	258,198	(50,947)
Provision for (benefit from) income taxes	1,521	142,466
Net income (loss)	256,677	(193,413)
Net income (loss) attributable to non-controlling interest	198,738	(1,109)
Net income (loss) attributable to Viper Energy Partners LP	$ 57,939	$ (192,304)

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

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Production data:		
Oil (MBbls)	6,068	5,956
Natural gas (MMcf)	13,672	11,486
Natural gas liquids (MBbls)	1,913	1,848
Combined volumes (MBOE)(1)	10,260	9,718
Average daily oil volumes (BO/d)	16,625	16,272
Average daily combined volumes (BOE/d)	28,110	26,551
Average sales prices:		
Oil ($/Bbl)	$ 65.51	$ 36.58
Natural gas ($/Mcf)	$ 3.60	$ 0.79
Natural gas liquids ($/Bbl)	$ 28.66	$ 10.88
Combined ($/BOE)(2)	$ 48.88	$ 25.41
Oil, hedged ($/Bbl)(3)	$ 50.25	$ 32.00
Natural gas, hedged ($/Mcf)(3)	$ 3.60	$ 0.02
Natural gas liquids ($/Bbl)(3)	$ 28.66	$ 10.88
Combined price, hedged ($/BOE)(3)	$ 39.86	$ 21.71
Average costs ($/BOE):		
Production and ad valorem taxes	$ 3.17	$ 2.04
General and administrative - cash component(4)	0.65	0.71
Total operating expense - cash	$ 3.82	$ 2.75
General and administrative - non-cash unit compensation expense	$ 0.11	$ 0.13
Interest expense, net	$ 3.32	$ 3.40
Depletion	$ 10.04	$ 10.34

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per one Bbl.
(2) Realized price net of all deducts for gathering, transportation and processing.
(3) Hedged prices reflect the impact of cash settlements on our matured commodity derivative transactions on our average sales prices.
(4) Excludes non-cash unit compensation for the respective periods presented.

Comparison of the Years Ended December 31, 2021 and 2020

Royalty Income

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

Royalty income increased $254.6 million during the year ended December 31, 2021 compared to 2020. Higher average prices contributed approximately $248.0 million of the total increase, due largely to the recovery in oil prices, and to a lesser extent, natural gas and natural gas liquids prices from historic lows experienced in the 2020 as discussed in "— *Overview*."

The 6% increase in production volumes during the year ended December 31, 2021 compared to 2020 contributed approximately $6.5 million of the total increase in royalty income. The increase in production was primarily attributable to new well additions between periods.

Production and Ad Valorem Taxes

The following table presents production and ad valorem taxes for the years ended December 31, 2021 and 2020:

	Year Ended December 31,					
	2021			2020		
	Amount (In thousands)	Per BOE	Percentage of Royalty Income	Amount (In thousands)	Per BOE	Percentage of Royalty Income
Production taxes	$ 25,966	$ 2.53	5.2 %	$ 12,101	$ 1.25	4.9 %
Ad valorem taxes	6,592	0.64	1.3	7,743	0.79	3.1
Total production and ad valorem taxes	$ 32,558	$ 3.17	6.5 %	$ 19,844	$ 2.04	8.0 %

In general, production taxes are directly related to production revenues and are based upon current year commodity prices. Production taxes as a percentage of royalty income for 2021 remained consistent with 2020. Ad valorem taxes are based, among other factors, on property values driven by prior year commodity prices. Ad valorem taxes as a percentage of royalty income for the same period in 2021 compared to 2020 decreased primarily due to improved average sales prices, while the tax valuation of oil and natural gas interests declined. We expect production and ad valorem taxes for 2022 to be approximately 7% to 8% of revenue.

Depletion

The $2.5 million, or 2%, increase in depletion expense for 2021 compared to 2020 was due primarily to an increase in production, partially offset by a decrease in the depletion rate to $10.04 from $10.34, respectively. The rate decrease largely resulted from higher SEC oil prices utilized in the reserve calculations in the 2021 period, lengthening the economic life of the reserve base and resulting in higher projected remaining reserve volumes on our wells.

Impairment

There was no impairment recorded for the year ended December 31, 2021. We recorded an impairment expense of $69.2 million as a result of the decline in commodity prices for the year ended December 31, 2020.

Net Interest Expense

Net interest expense for 2021 and 2020 was $34.0 million and $33.0 million, respectively. The increase of $1.0 million was due to increased borrowings during 2021 compared to 2020, as approximately $190.0 million of the Swallowtail Acquisition was funded with additional borrowings under the Operating Company's revolving credit facility in October 2021 as discussed in "—*2021 Transactions and Recent Developments*" above. This increase was partially offset by repayments of borrowings under the Operating Company's revolving credit facility and the Notes.

Derivative Instruments

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

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Gain (loss) on derivative instruments	$ (69,409)	$ (63,591)
Net cash receipts (payments) on derivatives	$ (92,585)	$ (36,998)

We recorded losses on our derivative instruments for the year ended December 31, 2021 and 2020 primarily due to market prices being higher than the strike prices on our derivative contracts. We are required to recognize all derivative instruments on our balance sheet as either assets or liabilities measured at fair value. We have not designated our 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 condensed consolidated statements of operations under the line item captioned "Gain (loss) on derivative instruments, net."

Gain (Loss) on Revaluation of Investment

We did not record a gain or loss on revaluation of investment for the year ended December 31, 2021, as we fully divested our equity interest in a limited partnership during 2020. We recorded loss on revaluation of investment of $8.6 million for the year ended December 31, 2020 primarily due to recording the remaining investment at its fair value during that period.

Provision for (Benefit from) Income Taxes

We recorded an income tax expense of $1.5 million and $142.5 million for the years ended December 31, 2021 and 2020, respectively. The change in our income tax provision was primarily due to the impact of recording a valuation allowance on our deferred tax assets during the first quarter of 2020. The total income tax provision for the year ended December 31, 2021 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the period primarily due to net income attributable to the non-controlling interest and the impact of maintaining a valuation allowance on our deferred tax assets. See Note 9—Income Taxes of the notes to the consolidated financial statements included elsewhere in this Annual Report for further details.

Liquidity and Capital Resources

Overview of Sources and Uses of Cash

As we pursue our business and financial strategy, we regularly consider which capital resources, including cash flow and equity and debt financings, are available to meet our future financial obligations and liquidity requirements. Our future ability to grow proved reserves will be highly dependent on the capital resources available to us. Our primary sources of liquidity have been cash flows from operations, proceeds from sales of non-core assets and investments, equity and debt offerings and borrowings under the Operating Company's credit agreement. Our primary uses of cash have been distributions to our unitholders, repayment of debt, capital expenditures for the acquisition of our mineral interests and royalty interests in oil and natural gas properties and repurchases of our common units. At December 31, 2021, we had approximately $235.4 million of liquidity consisting of $39.4 million in cash and cash equivalents and $196.0 million available under the Operating Company's credit agreement.

Our working capital requirements are supported by our cash and cash equivalents and the Operating Company's credit agreement. We may draw on the Operating Company's credit agreement 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 acquisitions of mineral and royalty interests, distributions, debt service obligations and repayment of debt maturities, common unit repurchase program and any amounts that may ultimately be paid in connection with contingencies.

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

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 Partnership 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 Flows

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

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Cash Flow Data:		
Net cash provided by (used in) operating activities	$ 307,114	$ 196,556
Net cash provided by (used in) investing activities	(281,176)	(16,283)
Net cash provided by (used in) financing activities	(5,611)	(164,754)
Net increase (decrease) in cash and cash equivalents	$ 20,327	$ 15,519

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which are the volatility of prices for oil and natural gas and the volume of oil and natural gas sold by our producers as discussed in "*—Results of Operations*" above. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, extreme weather conditions and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. The increase in net cash provided by operating activities during the year ended December 31, 2021 compared to the same period in 2020 was primarily driven by higher royalty income in 2021, which was largely offset by (i) changes in our working capital accounts, most notably through an increase in our royalty income accounts receivable in 2021 compared to 2020 due primarily to an increase in oil and gas prices on production sold in the fourth quarter of 2021 compared to the fourth quarter of 2020, the Swallowtail Acquisition, and the timing of our receipt of royalty income payments from our operators, (ii) an increase in cash paid for derivative settlements and (iii) an increase in production and ad valorem expenses due to the corresponding increase in royalty income.

Investing Activities

Net cash used in investing activities during the years ended December 31, 2021 and 2020, was primarily related to acquisitions of oil and natural gas interests.

Financing Activities

Net cash used in financing activities during the year ended December 31, 2021, was primarily related to net borrowings of $220.0 million under the Operating Company's revolving credit facility to fund the Swallowtail Acquisition, distributions of $176.6 million to our unitholders and $46.0 million of repurchases of our common units during the fourth quarter of 2021 as discussed below.

Net cash used in financing activities during the year ended December 31, 2020, was primarily related to distributions of $108.0 million to our unitholders, $24.0 million of common units repurchased as part of our unit repurchase program, repurchases of the Notes totaling $19.7 million, net of discounts during the second quarter of 2020, and net payments for borrowings under the Operating Company's revolving credit facility of $12.5 million.

Capital Resources

The Operating Company's Revolving Credit Facility

The Operating Company'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 $580.0 million as of December 31, 2021, based on the Operating Company's oil and natural gas reserves and other factors. At December 31, 2021, the Operating Company had elected a commitment amount of $500.0 million on its credit agreement with $304.0 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%.

As of December 31, 2021, the Operating Company was in compliance, and expects to be in compliance, with all financial maintenance covenants under its credit agreement.

See Note 6—Debt of the notes to the consolidated financial statements included elsewhere in this Annual Report for additional discussion of our outstanding debt at December 31, 2021.

Capital Requirements

Senior Notes

The outstanding Notes obligations total $479.9 million as of December 31, 2021. There are no principal amounts due until 2027. At December 31, 2021, we have a remaining aggregate interest expense obligation of $154.8 million on the Notes with $25.8 million being due each year from 2023 to 2027. The Notes are not subject to any mandatory redemption or sinking fund requirements. See Note 6—Debt of the notes to the consolidated financial statements included elsewhere in this Annual Report for further information on the Notes.

Unit Repurchase Program

On November 15, 2021, the board of directors of our General Partner approved an increase of the authorization of its common unit repurchase program to $150.0 million of the Partnership's outstanding common units and extended the authorization indefinitely. During the year ended December 31, 2021, the Partnership repurchased approximately $46.0 million of common units under the repurchase program. As of December 31, 2021, $80.0 million remains available for use to repurchase units under the repurchase program. See Note 7—Unitholders' Equity and Distributions of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of the unit repurchase program.

Cash Distributions

We paid total distributions of $176.5 million and $108.0 million on our common units and the Operating Company's Class B units during 2021 and 2020, respectively. Beginning with the first quarter of 2020, the board of directors of our General Partner revised the distribution policy to provide that the Operating Company would distribute a percentage of its available cash to its unitholders (including Diamondback and us) rather than all of its available cash as it had previously done.

The distribution for the fourth quarter of 2021 is payable on March 11, 2022 to common unitholders of record at the close of business on March 4, 2022. Based on the common units and Operating Company units held by Diamondback on February 22, 2022, the distribution payable to Diamondback for the fourth quarter of 2021 on March 11, 2022 will be approximately $43.1 million. See Note 7—Unitholders' Equity and Distributions of the notes to the consolidated financial statements included elsewhere in this Annual Report for further discussion of our distributions. We expect to continue paying quarterly cash distributions in respect of our common units. The board of directors of the General Partner may change the distribution policies at any time. We are not required to pay distributions to its common unitholders on a quarterly or other basis.

Critical Accounting Estimates

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

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

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

Royalty Interest and Revenue Recognition

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and natural gas liquids sales from third party operators other than Diamondback may not be received for 30 to 90 days after the date production is delivered. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded based upon the Partnership’s interest. Where available, historical actual data is used to calculate volume estimates for wells operated by third parties. If historical actual data is not available for these wells, engineering estimates are used to calculate expected volumes. As such, estimated volumes utilized in period end royalty income accruals are subject to revision as additional actual data becomes available and such revisions may have a material impact on our results of operations and our royalty income receivables. Pricing estimates are based upon actual prices realized in an area by adjusting the market price for the average basis differential from market on a basin-by-basin basis. We record the differences between our estimates and the actual amounts received for royalties from third parties in the month that payment is received from the producer. We have existing internal controls for our royalty income estimation process and related accruals, but actual third party royalty income in future periods could differ materially from estimated amounts. At December 31, 2021, our accrual for third party royalty was approximately $49.4 million. Actual revenues received from third parties differed by approximately $1.9 million or 7% compared to the accrual at December 31, 2020.

Oil and Natural Gas Accounting and Reserves

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

Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. 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 quantity estimates accounted for approximately 4% of the change in the total standardized measure of our reserves from December 31, 2020 to December 31, 2021, and were primarily related to negative revisions due to PUD downgrades during 2021.

Our unevaluated property costs are tracked by lease and prospect. 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 calculated value for each lease based on the total costs incurred for the lease divided by the number of acres available to develop compared to current market prices for acreage in the related basins. We also monitor information available from third party operators of our acreage for future drilling plans as part of our impairment assessment. At December 31, 2021, our unevaluated properties totaled $1.6 billion. No impairments were recorded on our proved oil and natural gas properties during the years ended December 31, 2021 and 2019; however, impairment expense of $69.2 million was recorded for the year ended December 31, 2020 as discussed further in Note 5—Oil and Natural Gas Interests 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. Any future impairment could be material to our consolidated financial statements.

Derivative Instruments

In order to reduce uncertainty around commodity prices received for our oil and natural gas operators' production, we enter into commodity price derivative contracts from time to time. 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 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 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. 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.

Income Taxes

We have elected to be treated as a corporation for U.S. federal income tax purposes. The amount of income taxes we record requires interpretations of complex rules and regulations of federal, state, and provincial tax jurisdictions. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized after considering all positive and negative evidence available concerning the realizability of our deferred tax assets. During the year ended December 31, 2020, we established a valuation allowance for the full amount of our deferred tax assets.

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

Recent Accounting Pronouncements

See Note 2—Summary of Significant Accounting Policies to in the notes of our consolidated financial statements included elsewhere in this Annual Report for a full listing of our significant accounting policies.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to the oil and natural gas production of our operators. Realized prices are driven primarily by the prevailing worldwide price for crude oil and prices for natural gas in the United States. Both crude oil and natural gas realized prices are also impacted by the quality of the product, supply and demand balances in local physical markets and the availability of transportation to demand centers. Pricing for oil and natural gas production has been historically volatile and unpredictable and the prices that our operators receive for production depend on many factors outside of our or their control. 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. Additionally, the Delta variant emerged in March 2021 and became highly transmissible in July 2021, and the Omicron variant emerged in November 2021, which contributed to additional pricing and demand volatility during 2021. While certain restrictions on conducting business that were implemented in response to the COVID-19 pandemic have been lifted as improved treatments and vaccinations for COVID-19 have been rolled-out globally since late 2020, we cannot predict events that may lead to future price volatility and the near term energy outlook remains subject to heightened levels of uncertainty.

We historically have used fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of our royalty income. Under our costless collar contracts, each collar has an established floor price and ceiling price. When the settlement price is below the floor price, the counterparty is required to make a payment to us and when the settlement price is above the ceiling price, we are required to make a payment to the counterparty. When the settlement price is between the floor and the ceiling, there is no payment required.

At December 31, 2021, we had a net liability derivative position related to our commodity price derivatives of $3.4 million, related to our contracts. Utilizing actual derivative contractual volumes under our contracts as of December 31, 2021, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position by $3.6 million to $7.0 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position by $2.4 million to $1.0 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.

Credit Risk

We are subject to risk resulting from the concentration of royalty interest revenues in producing oil and natural gas properties and receivables with a limited number of several significant purchasers. For the year ended December 31, 2021, three purchasers accounted for more than 10% of our revenue. For the years ended December 31, 2020 and 2019, four and three purchasers each accounted for more than 10% of our revenue, respectively. See Note 2—Summary of Significant Accounting Policies of the notes to the consolidated financial statements included elsewhere in this Annual Report for further details. We do not require collateral and the failure or inability of our significant purchasers to meet their obligations to us due to their liquidity issues, bankruptcy, insolvency or liquidation may adversely affect our financial results. Volatility in commodity pricing environment and macroeconomic conditions may enhance our purchaser credit risk.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under the Operating Company's credit agreement. The terms of the 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 0.50% 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% in the case of the alternative base rate and from 2.00% to 3.00% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is the least of the maximum credit amount, the aggregate elected commitment amount and the borrowing base. As of December 31, 2021, we had $304.0 million in outstanding borrowings. During the year ended December 31, 2021, the weighted average interest rate was 2.35%.

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

Management conducted an evaluation of the effectiveness of the Partnership'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 Partnership's internal control over financial reporting and determined that the Partnership 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 Partnership included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Partnership's internal control over financial reporting at December 31, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Partnership'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

General Partner and Unitholders
Viper Energy Partners LP

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Viper Energy Partners LP (a Delaware limited partnership) and subsidiary (the “Partnership”) 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 Partnership 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 Partnership 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 Partnership’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 Partnership’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 Partnership 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

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Management of Viper Energy Partners LP

We are managed and operated by the board of directors and the executive officers of our General Partner, the latter of whom are employed by Diamondback.

Diamondback owns all of the membership interests in our General Partner. As a result of owning our General Partner, Diamondback has the right to appoint all members of the board of directors of our General Partner, including the independent directors. Our common unitholders are not entitled to elect our General Partner or its directors or otherwise directly participate in our management or operation. Our General Partner owes certain duties to our common unitholders as well as a fiduciary duty to its owner.

The executive officers of our General Partner manage the day-to-day affairs of our business. All of the executive officers of our General Partner also serve as executive officers of Diamondback. The executive officers listed below allocate their time between managing our business and the business of Diamondback. In addition, Messrs. Stice, Van't Hof and Zmigrosky and Ms. Dick allocate a portion of their time to Rattler Midstream LP, Diamondback's other publicly traded subsidiary, which we refer to as Rattler.

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our General Partner as of January 31, 2022. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board of directors of our General Partner. There are no family relationships among any of our General Partner's directors or executive officers.

Name	Age	Position With Our General Partner
Travis D. Stice	60	Chief Executive Officer and Director
Kaes Van't Hof	35	President
Teresa L. Dick	52	Chief Financial Officer, Executive Vice President and Assistant Secretary
Thomas F. Hawkins	68	Executive Vice President—Land
Matt Zmigrosky	43	Executive Vice President, General Counsel and Secretary
Steven E. West	61	Chairman of the Board
W. Wesley Perry	65	Director
Spencer D. Armour	67	Director
James L. Rubin	37	Director
Rosalind Redfern Grover	80	Director

Travis D. Stice. Mr. Stice has served as Chief Executive Officer and a director of our General Partner since February 2014. He has served as Chief Executive Officer of Diamondback since January 2012 and as a director since November 2012. Mr. Stice has also served as the Chief Executive Officer and a director of the General Partner of Rattler since July 2018. Prior to these positions with our General Partner, Diamondback and Rattler's general partner, Mr. Stice served as Diamondback's President and Chief Operating Officer from April 2011 to January 2012. From November 2010 to April 2011, Mr. Stice served as a Production Manager of Apache Corporation, an oil and gas exploration company. Mr. Stice served as a Vice President of Laredo Petroleum Holdings, Inc., an oil and gas exploration company, from September 2008 to September 2010 and as a Development Manager of ConocoPhillips/Burlington Resources Mid-Continent Business Unit, an oil and gas exploration company, from April 2006 until August 2008. Prior to that, Mr. Stice held a series of positions at Burlington Resources, an oil and gas exploration company, most recently as a General Manager, Engineering, Operations and Business Reporting of its Mid Continent Division from January 2001 until Burlington Resources' acquisition by ConocoPhillips in March 2006. Mr. Stice has over 35 years of experience in production operations, reservoir engineering, production engineering and unconventional oil and gas exploration and over 20 years of management experience. Mr. Stice graduated from Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. He is a registered engineer in the State of Texas and is a 35-year member of the Society of Petroleum Engineers.

We believe Mr. Stice’s expertise and extensive industry and executive management experience, including at Diamondback, make him a valuable asset to the board of directors of our General Partner.

Kaes Van’t Hof. Mr. Van't Hof has served as President of our General Partner since March 2017. He has served as Diamondback’s Chief Financial Officer and Executive Vice President of Business Development since March 2019 after joining Diamondback in July 2016 as Vice President and serving as its Senior Vice President—Strategy and Corporate Development from February 2017 to February 2019. Mr. Van’t Hof has also served as President and director of the General Partner of Rattler since July 2018. Prior to his positions with our General Partner, Diamondback and Rattler’s general partner, Mr. Van't Hof served as Chief Executive Officer for Bison Drilling and Field Services from September 2012 to June 2016. From August 2011 to August 2012, Mr. Van't Hof was an analyst for Wexford Capital LP responsible for developing operating models and business plans, including in connection with our initial public offering, and before that worked for the Investment Banking-Financial Institutions Group of Citigroup Global Markets, Inc. from February 2010 to August 2011. Mr. Van't Hof was a professional tennis player from May 2008 to January 2010. Mr. Van't Hof received a Bachelor of Science in Accounting and Business Administration from the University of Southern California.

Teresa L. Dick. Ms. Dick has served as Chief Financial Officer, Executive Vice President and Assistant Secretary of our General Partner since February 2017 and served as Chief Financial Officer, Senior Vice President and Assistant Secretary from February 2014 to February 2017. She has also served as Diamondback’s Executive Vice President and Chief Accounting Officer since March 2019. Ms. Dick served as Diamondback’s Executive Vice President and Chief Financial Officer from February 2017 to February 2019, as its Assistant Secretary since October 2012, as its Chief Financial Officer and Senior Vice President from November 2009 to February 2017 and as its Corporate Controller from November 2007 until November 2009. Ms. Dick has also served as Chief Financial Officer, Executive Vice President and Assistant Secretary of the general partner of Rattler since July 2018. From June 2006 to November 2007, Ms. Dick held a key management position as the Controller/Tax Director at Hiland Partners, a publicly traded midstream energy master limited partnership. Ms. Dick has over 20 years of accounting experience, including over nine years of public company experience in both audit and tax areas. Ms. Dick received her Bachelor of Business Administration degree in Accounting from the University of Northern Colorado. She is a certified public accountant and a member of the American Institute of CPAs and the Council of Petroleum Accountants Societies.

Thomas F. Hawkins. Mr. Hawkins has served as Executive Vice President—Land of our General Partner and Diamondback since March 2019. Prior to these positions, he served as Senior Vice President—Land of our General Partner and Diamondback from March 2017 to February 2019. Prior to his positions with us and Diamondback, Mr. Hawkins was an independent consultant for land activities from July 2016 to February 2017. Mr. Hawkins has over 40 years of experience in the oil and gas industry. Mr. Hawkins spent seven years with Oasis Petroleum Inc., an oil and gas company, as its Senior Vice President of Land or in related capacities from March 2009 to June 2016. Until February 2009, Mr. Hawkins spent 31 years with ConocoPhillips and Burlington Resources (which ConocoPhillips acquired in 2006). During that time, Mr. Hawkins held various operations and managerial positions in the land, marketing, planning and the corporate acquisitions and divestitures groups. Mr. Hawkins has worked in several major regions in the continental United States, including the San Juan Basin, the Williston Basin and the Austin Chalk/Wilcox Trends in South Texas. Mr. Hawkins holds a Bachelor of Business Administration in Finance from the University of Texas at El Paso.

Matt Zmigrosky. Mr. Zmigrosky has served as Executive Vice President, General Counsel and Secretary of our General Partner since February 2019. Since February 2019, Mr. Zmigrosky has also served as Executive Vice President, General Counsel and Secretary of both Diamondback and the general partner of Rattler. Before joining us, Diamondback and Rattler’s general partner, Mr. Zmigrosky was in the private practice of law, most recently as a partner in the corporate section of Akin Gump Strauss Hauer & Feld LLP from October 2012 to February 2019, where he worked extensively with Diamondback and its subsidiaries. Mr. Zmigrosky received a Bachelor of Science in Management degree in finance from Tulane University and a Juris Doctorate degree from Southern Methodist University Dedman School of Law.

Steven E. West. Mr. West has served as Chairman of the Board of our General Partner since February 2014 and as a director and chairman of the general partner of Rattler since May 2019. Mr. West has also served as a director of Diamondback since December 2011 and as its Chairman of the Board since October 2012. He served as Diamondback's Chief Executive Officer from January 1, 2009 to December 31, 2011. From January 2011 until December 2016, Mr. West was a partner at Wexford Capital LP, focusing on Wexford’s private equity energy investments. From August 2006 until December 2010, Mr. West served as senior portfolio advisor at Wexford. From August 2003 until August 2006, he was the chief financial officer of Sunterra Corporation, a former Wexford portfolio company. From December 1993 until July 2003, Mr. West held senior financial positions at Coast Asset Management and IndyMac Bank. Prior to that, he worked at First Nationwide Bank, Lehman Brothers and Peat Marwick Mitchell & Co., the predecessor of KPMG LLP. Mr. West earned a Bachelor of Science degree in Accounting from California State University, Chico.

We believe that Mr. West's background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on the board of directors of our General Partner. In particular, we believe Mr. West's strengths in the following core competencies provide value to our board of directors: Corporate Governance; Finance/Capital Markets; Financial Reporting/Accounting Experience; Industry Background; Executive Experience; Executive Compensation; and Risk Management.

W. Wesley Perry. Mr. Perry has been a member of the board of directors of our General Partner since June 2014. Mr. Perry has served as a director of Genie Energy Ltd., an independent retail energy provider, since October 2011, currently serves as the chair of its audit committee and a member of its compensation, nominating, corporate governance and technology committees and has served as the chairman of the board of directors of Genie Energy International Corporation since September 2009. Mr. Perry also serves as manager of PBEX, LLC, an oil and gas exploration and development company, a position he has held since July 2012. Mr. Perry has served as manager of S.E.S. Investments, Ltd., an oil and gas investment company, since 1985. He served as Chief Executive Officer of E.G.L. Resources, Inc., an oil and gas production company, from July 2008 until December 2019 and served as its President from 2003 to July 2008. Mr. Perry was a director of UTG, Inc., an insurance holding company, from 2001 to 2013 and served on its Audit Committee. Mr. Perry served on the Midland City Council from 2002 to 2008 and as Mayor of Midland from 2008 through 2014. He is the Chairman of the Milagros Foundation and a trustee of the Abell-Hangar Foundation. He has a Bachelor of Science degree in Engineering from the University of Oklahoma.

We believe that Mr. Perry's extensive experience in the oil and gas industry and his strong financial background qualify him to serve on the board of directors of our General Partner.

Spencer D. Armour. Mr. Armour has been a member of the board of directors of our General Partner since July 2017. Mr. Armour has over 30 years of executive and entrepreneurial experience in the energy services industry. Mr. Armour has served as a partner of Geneses Investments since February 2019. He served as President of PT Petroleum LLC in Midland, Texas from March 2013 until January 2019. He was the Vice President of Corporate Development for Basic Energy Services, Inc. from 2007 to 2008, which acquired Sledge Drilling Corp., a company Mr. Armour co-founded and served as Chief Executive Officer for from 2005 to 2006. From 1998 through 2005, he served as Executive Vice President of Patterson-UTI Energy, Inc., which acquired Lone Star Mud, Inc., a company Mr. Armour founded and served as President from 1986 to 1997. Mr. Armour has served as a director of ProPetro Holding Corp. since February 2013 and as a director of CES Energy since December 2018. Mr. Armour also served on the Patterson-UTI Board of Directors from 1999 through 2001. Mr. Armour received a Bachelor of Science in Economics from the University of Houston and was appointed to the University of Houston System Board of Regents in 2011 by former Texas Governor Rick Perry.

We believe that Mr. Armour's extensive experience in the oil and gas industry qualify him to serve on the board of directors of our General Partner.

James L. Rubin. Mr. Rubin has been a member of the board of directors of our General Partner since June 2014. He has served as a partner at Wexford since 2012 and currently serves as Portfolio Manager and Co-Head of Equities and as a member of Wexford's hedge fund investment committee. From 2006 to 2012, he served as an analyst and later as Vice President, focusing on Wexford's public and private energy investments. Mr. Rubin graduated cum laude from Yale University with a Bachelor of Arts degree with honors in political science and economics.

We believe that Mr. Rubin's strong financial background qualifies him to serve on the board of directors of our General Partner.

Rosalind Redfern Grover. Ms. Grover has been a member of the board of directors of our General Partner since December 2014. Ms. Grover served as Chairman of the Board of Flag-Redfern Oil Company until the company was sold to Kerr-McGee Corporation in 1988. She has served as the President of Redfern Enterprises, Inc., an independent oil and gas producer, since 1989 and as the Chief Executive Officer of Redfern & Grover Resources, LLC, an independent oil and gas producer, since 2014. Ms. Grover holds Bachelors and Masters degrees from the University of Arizona.

We believe that Ms. Grover's extensive experience in the oil and gas industry, including with oil and gas partnerships, qualifies her to serve on the board of directors of our General Partner.

Director Independence and Diversity

The board of directors of our General Partner has six directors, five of whom are independent as defined under the independence standards established by Nasdaq and the Exchange Act. Steven E. West, W. Wesley Perry, James L. Rubin, Spencer D. Armour and Rosalind Redfern Grover serve as the independent members of the board of directors of our General Partner. Although a majority of the board of directors of our General Partner is independent, Nasdaq does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our General Partner, disclose details regarding board diversity or establish a compensation committee or a nominating and corporate governance committee. However, our General Partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by Nasdaq and the Exchange Act.

The board of directors of our General Partner has established an independent audit committee and a conflicts committee, discussed in more detail below, and has diverse representatives on its board, including a female director.

Board Leadership Structure and Role in Risk Oversight

Leadership of our General Partner's board of directors is vested in the chairman of the board. Steven E. West serves as the chairman of the board of directors of our General Partner and as a director of Diamondback. Mr. West was also the chairman of the board of Diamondback from October 2012 to February 2022, when he was succeeded in that role by Mr. Stice. Our General Partner's board of directors has determined that Mr. West's roles of chairman of the board of directors of our General Partner and a director of Diamondback allows the board of directors to take advantage of the leadership skills of Mr. West and that Mr. West's in-depth knowledge of, and experience in, our business, history, structure and organization facilitates timely communications between the board of directors of Diamondback and the board of directors of our General Partner.

As a partnership engaged in the oil and natural gas industry, we face a number of risks, including risks associated with supply of and demand for oil and natural gas, volatility of oil and natural gas prices, exploring for, developing, producing and delivering oil and natural gas, declining production, environmental and other government regulations and taxes, extreme weather conditions that can affect oil and natural gas operations over a wide area, adequacy of our insurance coverage, political instability or armed conflict in oil and natural gas producing regions and the overall economic environment. Management is responsible for the day-to-day management of risks we face as a partnership, while the board of directors of our General Partner, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors of our General Partner has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate and functioning as designed.

The board of directors of our General Partner believes that full and open communication between management and the board is essential for effective risk management and oversight. The chairman of the board of directors of our General Partner meets regularly with the Chief Executive Officer and the Chief Financial Officer to discuss strategy and risks facing the partnership. Executive officers may attend the board meetings of our General Partner and are available to address any questions or concerns raised by the board on risk management-related and any other matters. Other members of our management team periodically attend the board meetings or are otherwise available to confer with the board to the extent their expertise is required to address risk management matters. Periodically, the board of directors of our General Partner receives presentations from senior management on strategic matters involving our operations. During such meetings, the board also discusses strategies, key challenges, and risks and opportunities for the partnership with senior management.

While the board of directors of our General Partner is ultimately responsible for risk oversight at the partnership, its two committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk management in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements, and discusses policies with respect to risk assessment and risk management. The conflicts committee assists the board in fulfilling its oversight responsibilities with respect to specific matters that the board believes may involve conflicts of interest.

Meetings of the Board of Directors

During 2021, the board of directors of our General Partner met five times. Each director attended 100% of the meetings of the board and the committees of the board on which he or she served that occurred during 2021.

Communications with Directors

Unitholders or interested parties may communicate directly with the board of directors of our General Partner, any committee of the board, any independent directors, or any one director, by sending written correspondence by mail addressed to the board, committee or director to the attention of our Secretary at the following address: c/o Secretary, Viper Energy Partners LP, 500 West Texas, Suite 1200, Midland, Texas. Communications are distributed to the board of directors, committee of the board of directors, or director as appropriate, depending on the facts and circumstances outlined in the communication. Commercial solicitations or communications will not be forwarded.

Committees of the Board of Directors

The board of directors of our General Partner has an audit committee and a conflicts committee. We do not have a compensation committee or a nominating and corporate governance committee. Rather, the board of directors of our General Partner has authority over compensation matters and nominating and corporate governance matters.

Audit Committee

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has unrestricted access to the audit committee and our management, as necessary. The audit committee has adopted a charter, which is available on our website under the “corporate governance” section at http://ir.viperenergy.com.

W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover currently serve on the audit committee, and Mr. Perry serves as the chairman. The board of directors of our General Partner has determined that each of W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover meet the independence and experience standards established by the Nasdaq and the Exchange Act and that Mr. Perry is an “audit committee financial expert” as defined under SEC rules.

Conflicts Committee

Our conflicts committee reviews specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee determines if the resolution of the conflict of interest is in our best interest. The members of the conflicts committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates, including Diamondback, and must meet the independence standards established by Nasdaq and the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders. W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover are the members of the conflicts committee.

Corporate Governance

The board of directors of our General Partner has adopted a Code of Business Conduct and Ethics, or Code of Ethics, that applies to all employees, including executive officers, and directors of our General Partner. Amendments to or waivers from the Code of Ethics will be disclosed on our website. We have also made the Code of Ethics available on our website under the “Corporate Governance” section at http://ir.viperenergy.com.

Reimbursement of Expenses of our General Partner

Our partnership agreement requires us to reimburse our General Partner and its affiliates, including Diamondback, for all expenses they incur and payments they make on our behalf in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

As is commonly the case for publicly traded limited partnerships, we have no officers. Our General Partner has the sole responsibility for conducting our business and for managing our operations, and its board of directors and executive officers make decisions on our behalf. Our General Partner’s executive officers are employed and compensated by Diamondback or a subsidiary of Diamondback. All of the executive officers that are responsible for managing our day-to-day affairs are also current executive officers of Diamondback.

All of the executive officers of our General Partner have responsibilities to us, Diamondback and Rattler, Diamondback’s other publicly traded subsidiary, and allocate their time between managing our business and managing the businesses of Diamondback and Rattler. Since all of these executive officers are employed by Diamondback or one of its subsidiaries, the responsibility and authority for compensation-related decisions for them resides with Diamondback’s compensation committee. Diamondback has the ultimate decision-making authority with respect to the total compensation of the executive officers that are employed by Diamondback including, subject to the terms of the partnership agreement, the portion of that compensation that is allocated to us pursuant to Diamondback’s allocation methodology. Any such compensation decisions are not subject to any approvals by the board of directors of our General Partner or any committees thereof. However, all determinations with respect to awards that are made to executive officers, key employees and non-employee directors under the LTIP are made by the board of directors of our General Partner. Please see the description of the LTIP below under the heading “Long-Term Incentive Plan.”

The executive officers of our General Partner, as well as the employees of Diamondback who provide services to us, may participate in employee benefit plans and arrangements sponsored by Diamondback, including plans that may be established in the future. Certain of our General Partner’s executive officers and employees and certain employees of Diamondback who provide services to us currently hold grants under Diamondback’s and Rattler’s equity incentive plans. Except with respect to any awards that may be granted under the LTIP, the executive officers of our General Partner do not receive separate amounts of compensation in relation to the services they provide to us. In accordance with the terms of our partnership agreement, we reimburse Diamondback for compensation related expenses attributable to the portion of the executive’s time dedicated to providing services to us. Although we bear an allocated portion of Diamondback’s costs of providing compensation and benefits to employees who serve as executive officers of our General Partner, we have no control over such costs and did not establish and do not direct the compensation policies or practices of Diamondback. Except with respect to awards granted under the LTIP, compensation paid or awarded by us in 2021 consisted only of the portion of compensation paid by Diamondback that is allocated to us and our General Partner pursuant to Diamondback’s allocation methodology and subject to the terms of the partnership agreement.

A full discussion of the compensation programs for Diamondback’s executive officers and the policies and philosophy of the compensation committee of Diamondback’s board of directors will be set forth in Diamondback’s 2022 proxy statement under the heading “Compensation Discussion and Analysis.” Specifically, compensation paid directly by us through our LTIP or indirectly by us through reimbursement pursuant to our partnership agreement will be included in the amounts set forth in certain of the tables included in Diamondback’s 2022 proxy statement, with awards outstanding pursuant to our LTIP separately identified.

Long-Term Incentive Plan

In order to incentivize our management and directors to continue to grow our business, the board of directors of our General Partner adopted the LTIP for employees, officers, consultants and directors of our General Partner and any of its affiliates, including Diamondback, who perform services for us.

The purpose of the LTIP is to provide a means to attract and retain individuals who are essential to our growth and profitability and to encourage them to devote their best efforts to advancing our business by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common units. The 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 (collectively, “awards”). These awards are intended to align the interests of employees, officers, consultants and directors with those of our unitholders and to give such individuals the opportunity to share in our long-term performance. Any awards that are made under the LTIP will be approved by the board of directors of our General Partner or a committee thereof that may be established for such purpose. We will be responsible for the cost of awards granted under the LTIP.

During 2021, our General Partner made grants under the LTIP of phantom units to the non-employee directors of our General Partner (see "Director Compensation" below for information regarding those awards). No grants under the LTIP were made to the executive officers of our General Partner in 2021.

Administration

The LTIP is administered by the board of directors of our General Partner pursuant to its terms and all applicable state, federal, or other rules or laws. The board of directors of our General Partner has the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or in shares of our common units), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), accelerate the vesting provisions associated with an award, delegate duties under the LTIP and execute all other responsibilities permitted or required under the LTIP.

Change in Control

Upon a "change in control" (as defined in the LTIP), the committee may, in its discretion, (i) remove any forfeiture restrictions applicable to an award, (ii) accelerate the time of exercisability or vesting of an award, (iii) require awards to be surrendered in exchange for a cash payment, (iv) cancel unvested awards without payment or (v) make adjustments to awards as the committee deems appropriate to reflect the change in control.

Termination of Employment or Service

The consequences of the termination of a participant's employment, consulting arrangement or membership on the board of directors of our General Partner will be determined by the plan administrator in the terms of the relevant award agreement.

Compensation Report

Neither we nor the board of directors of our General Partner has a compensation committee. The board of directors of our General Partner has reviewed and discussed the Compensation Discussion and Analysis set forth above. Based on this review and discussion, the board of directors of our General Partner has approved the Compensation Discussion and Analysis for inclusion in this Annual Report.

The Board of Directors of Viper Energy Partners GP LLC
Travis D. Stice
Steven E. West
W. Wesley Perry
Spencer D. Armour
James L. Rubin
Rosalind Redfern Grover

Director Compensation

The executive officers or employees of our General Partner or of Diamondback who also serve as directors of our General Partner do not receive additional compensation for their service as a director of our General Partner. Directors of our General Partner who are not executive officers or employees of our General Partner or of Diamondback receive compensation as "non-employee directors" as set by our General Partner's board of directors.

Each non-employee director receives a compensation package that consists of an annual cash retainer of $60,000 plus an additional annual payment of $15,000 for the chairperson and $10,000 for each other member of the audit committee and $10,000 for the chairperson and $5,000 for each other member of each other committee. In addition, each non-employee director receives an equity award of phantom units under the LTIP granted annually at the close of business on July 10th of each year or, if not a business day, the first business day thereafter. The number of phantom units awarded is calculated by dividing $100,000 by the average closing price of our common units for the five trading days immediately preceding the date of grant. The awards vest on the first anniversary of the grant date. Our directors are also reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees.

Each member of the board of directors of our General Partner is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth the aggregate dollar amount of all fees paid to each of the non-employee directors of our General Partner during 2021 for their services on the board:

Name	Fees Earned or Paid in cash(a)	Unit Awards(b)	Total
Spencer D. Armour[(c)(d)]	$ 75,000	$ 100,833	$ 175,833
Rosalind Redfern Grover[(c)(d)]	$ 75,000	$ 100,833	$ 175,833
W. Wesley Perry[(c)(d)]	$ 85,000	$ 100,833	$ 185,833
James L. Rubin[(c)(d)]	$ 60,000	$ 100,833	$ 160,833
Steven E. West[(c)(d)]	$ 60,000	$ 100,833	$ 160,833

(a) This column reflects the value of a director's annual retainer.
(b) The amount in this column represents the aggregate grant date fair value of phantom units granted in the fiscal year calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, "Compensation - Stock Compensation." Distribution equivalent rights are not reflected in the aggregate grant date fair value of phantom unit awards.
(c) Each of Ms. Grover and Messrs. Armour, Perry, Rubin and West received a grant of 9,970 phantom units on July 10, 2020, which vested and settled on July 10, 2021, pursuant to the LTIP, with each unit having a grant date fair value of $9.82. Each phantom unit is the economic equivalent of one of our common units.
(d) Each of Ms. Grover and Messrs. Armour, Perry, Rubin and West received a grant of 5,513 phantom units on July 12, 2021, which will vest and settle on July 12, 2022, pursuant to the LTIP, with each unit having a grant date fair value of $18.29. Each phantom unit is the economic equivalent of one of our common units.

Mr. Stice is a director of our General Partner, but is also an executive officer of our General Partner and Mr. Stice is an employee of Diamondback E&P LLC. Mr. Stice has received awards pursuant to the LTIP for his service as an executive officer or employee, respectively, and unrelated to his service as director. These awards are reflected in the tables contained in Diamondback's 2022 proxy statement under the heading "Compensation Discussion and Analysis."

Compensation Committee Interlocks and Insider Participation

As previously noted, our General Partner's board of directors is not required to maintain, and does not maintain, a separate compensation committee. Mr. Stice, a director and executive officer of our General Partner, is also a director and executive officer of Diamondback. However, all compensation decisions with respect to Mr. Stice are made by Diamondback and Mr. Stice does not receive any compensation directly from us or our General Partner except for awards under our LTIP. As described in "—Compensation Discussion and Analysis," decisions regarding the compensation of our General Partner's executive officers are made by Diamondback. Please read "Items 1 and 2. Business and Properties–Our Relationship with Diamondback" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" for more information about relationships among us, our General Partner and Diamondback.

Compensation Policies and Practices as They Relate to Risk Management

We do not have any employees. We are managed and operated by the directors and officers of our General Partner and employees of Diamondback perform services on our behalf. Please read "—Compensation Discussion and Analysis" and "Items 1 and 2. Business and Properties–Our Relationship with Diamondback" for more information about this arrangement. For an analysis of any risks arising from Diamondback's compensation policies and practices, please read Diamondback's 2022 proxy statement. We have made awards of unit options subject to time-based vesting under our LTIP, which we believe drive a long-term perspective and which we believe make it less likely that executive officers will take unreasonable risks because the unit options retain value even in a depressed market.

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

Holdings of Officers and Directors

The following table presents information regarding the beneficial ownership of our common units as of January 31, 2022 by:

- our General Partner;
- each of our General Partner's directors and executive officers; and
- all of our General Partner's directors and executive officers as a group.

Name of Beneficial Owner	Common Units Beneficially Owned[1]	Percentage of Common Units Beneficially Owned
Diamondback Energy, Inc.	731,500	1.0%
Viper Energy Partners GP LLC	—	—
Travis D. Stice[2]	106,169	*
Kaes Van't Hof	35,362	*
Teresa L. Dick	11,540	*
Thomas F. Hawkins	—	—
Matt Zmigrosky	4,253	*
Steven E. West[3]	72,777	*
W. Wesley Perry[3]	58,732	*
Spencer D. Armour[3]	22,704	*
James L. Rubin[4]	—	—
Rosalind Redfern Grover[3]	33,066	*
All directors and executive officers as a group (10 persons)	344,603	*

* Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, (i) common units subject to options held by that person that are exercisable as of January 31, 2022 and (ii) common units subject to options or phantom units held by that person that are exercisable or vesting within 60 days of January 31, 2022 are all deemed to be beneficially owned. These common units, however, are not deemed outstanding for the purpose of computing the percentage ownership of each other person. The percentage of common units beneficially owned is based on 76,966,203 common units outstanding as of January 31, 2022. Unless otherwise indicated, all amounts exclude common units issuable upon the exercise of outstanding options and vesting of phantom units that are not exercisable and/or vested as of January 31, 2022 or within 60 days of January 31, 2022. Unless otherwise noted, the address for each beneficial owner listed below is 500 West Texas Avenue, Suite 1200, Midland, Texas 79701. Except as noted, each unitholder in the above table is believed to have sole voting and sole investment power with respect to the units beneficially held.

(2) All of these units are held by Stice Investments, Ltd., which is managed by Stice Management, LLC, its General Partner. Mr. Stice and his spouse hold 100% of the membership interests in Stice Management, LLC, of which Mr. Stice is the manager.

(3) Excludes 5,513 phantom units that are scheduled to vest on July 12, 2022.

(4) Excludes 39,732 common units (representing vested phantom units previously granted to Mr. Rubin) and 5,513 phantom units that are scheduled to vest on July 12, 2022, all of which have been assigned by Mr. Rubin to Wexford under the terms of his employment with Wexford.

The following table sets forth, as of January 31, 2022, the number of shares of common stock of Diamondback beneficially owned by each of the directors and executive officers of our General Partner and all directors and executive officers of our General Partner as a group.

Name of Beneficial Owner	Shares of Diamondback Common Stock Beneficially Owned[1]	
	Amount and Nature of Beneficial Ownership	Percentage of Class
Travis D. Stice[2]	403,324	*
Kaes Van't Hof[3]	45,615	*
Teresa L. Dick[4]	49,535	*
Thomas F. Hawkins[5]	12,648	*
Matt Zmigrosky[6]	14,175	*
Steven E. West[7]	3,756	*
W. Wesley Perry	—	—
Spencer D. Armour	—	—
James L. Rubin	—	—
Rosalind Redfern Grover	—	—
All directors and executive officers as a group (10 persons)	529,053	*

* Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, (i) shares of common stock subject to options held by that person that are exercisable as of January 31, 2022 and (ii) shares of common stock subject to options or restricted stock units held by that person that are exercisable or vesting within 60 days of January 31, 2022, are all deemed to be beneficially owned. These shares, however, are not deemed outstanding for the purpose of computing the percentage ownership of each other person. The percentage of shares beneficially owned is based on 177,412,057 shares of common stock outstanding as of January 31, 2022. Unless otherwise indicated, all amounts exclude shares issuable upon the exercise of outstanding options and vesting of restricted stock units that are not exercisable and/or vested as of January 31, 2022 or within 60 days of January 31, 2022. Except as noted, each stockholder in the above table is believed to have sole voting and sole investment power with respect to the shares of common stock beneficially held.

(2) All of these shares are held by Stice Investments, Ltd., which is managed by Stice Management, LLC, its general partner. Mr. Stice and his spouse hold 100% of the membership interests in Stice Management, LLC, of which Mr. Stice is the manager. Includes 26,325 restricted stock units, that are scheduled to vest on March 1, 2022. Excludes 11,499 restricted stock units, that are scheduled to vest on March 1, 2023. Also excludes (i) 49,436 performance-based restricted stock units awarded on March 1, 2019, that vested effective December 31, 2021 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021 by Diamondback's compensation committee, (ii) 66,714 performance-based restricted stock units awarded to Mr. Stice on March 1, 2020, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2022 and (iii) 51,748 performance-based restricted stock units awarded to Mr. Stice on March 1, 2021, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2023.

(3) Includes 12,955 restricted stock units, that are scheduled to vest on March 1, 2022. Excludes (i) 6,038 restricted stock units, that are scheduled to vest on March 1, 2023, (ii) 8,790 restricted stock units, that are scheduled to vest in five equal annual installments beginning on March 1, 2025, (iii) 23,070 performance-based restricted stock units awarded on March 1, 2019, that vested effective December 31, 2021 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021 by Diamondback's compensation committee, (iv) 13,183 performance-based restricted stock units awarded to Mr. Van't Hof on March 1, 2019 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholders return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021, that are scheduled to vest in five equal installments beginning on March 1, 2025, (v) 31,133 performance-based restricted stock units awarded to Mr. Van't Hof on March 1, 2020, that are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2022 and (vi) 27,168 performance-based restricted stock units awarded to Mr. Van't Hof on March 1, 2021, which are subject to the satisfaction of certain stockholder

return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2023.

(4) Includes 7,403 restricted stock units, that are scheduled to vest on March 1, 2022. Excludes 3,450 restricted stock units, that are scheduled to vest on March 1, 2023. Also excludes (i) 13,183 performance-based restricted stock units awarded to Ms. Dick on March 1, 2019, that vested effective December 31, 2021 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021 by Diamondback's compensation committee, (ii) 17,790 performance-based restricted stock units awarded to Ms. Dick on March 1, 2020, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2022 and (iii) 15,524 performance-based restricted stock units awarded to Ms. Dick on March 1, 2021, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2023.

(5) Includes 4,811 restricted stock units that are scheduled to vest on March 1, 2022. Excludes 2,243 restricted stock units that are scheduled to vest on March 1, 2023. Also excludes 8,569 performance-based restricted stock units awarded to Mr. Hawkins on March 1, 2019 that vested effective December 31, 2021 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021 by Diamondback's compensation committee, (ii) 11,564 performance-based restricted stock units awarded to Mr. Hawkins on March 1, 2020 that are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2022 and (iii) 10,091 performance-based restricted stock units awarded to Mr. Hawkins on March 1, 2021, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2023.

(6) Includes 5,922 restricted stock units, that are scheduled to vest on March 1, 2022. Excludes 2,760 restricted stock units, that are scheduled to vest on March 1, 2023. Also excludes (i) 10,546 performance-based restricted stock units awarded to Mr. Zmigrosky on March 1, 2019, that vested effective December 31, 2021 (representing 100% vesting of the originally reported amount) based upon final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ended on December 31, 2021 by Diamondback's compensation committee and (ii) 14,232 performance-based restricted stock units awarded to Mr. Zmigrosky on March 1, 2020, that are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2022 and (iii) 12,420 performance-based restricted stock units awarded to Mr. Zmigrosky on March 1, 2021, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2023.

(7) Excludes 2,435 restricted stock units that are scheduled to vest on the earlier of the one-year anniversary of the date of grant and the date of the 2022 annual meeting of stockholders of Diamondback.

Holdings of Major Stockholders

The following table sets forth certain information regarding the beneficial ownership of our common units and Class B units as of January 31, 2021 by each unitholder known by us to beneficially own 5% or more of our common units or Class B units.

MAJOR UNITHOLDER TABLE

	Common Units		Class B Units	
Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)	Percentage of Class Beneficially Owned	Amount and Nature of Beneficial Ownership(1)	Percentage of Class Beneficially Owned
Diamondback Energy, Inc.(2) 500 West Texas Avenue, Suite 1200 Midland, Texas 79701	731,500	1.0 %	90,709,946	100 %
Blackstone, Inc.(3) 345 Park Avenue New York, NY 10154	13,707,227	17.8 %		
Wellington Management Group LLP(4) c/o Wellington Management Company LLP 280 Congress Street Boston, MA 02210	9,642,118	12.5 %	—	—
Santa Elena Minerals, LP(5) 400 W. Illinois, Suite 1300 Midland, TX 79701	5,152,124	6.7 %	—	—

(1) Beneficial ownership is determined in accordance with SEC rules. The percentage of common units beneficially owned is based on 76,966,203 common units outstanding as of January 31, 2021. Except as noted, each unitholder in the above table is believed to have sole voting and sole investment power with respect to the common units and Class B units beneficially held.

(2) Diamondback Energy, Inc. is a publicly traded company and holds 731,500 common units and 90,709,946 Class B units, with the same aggregate number of units of the Operating Company (each, an "OpCo unit") that are exchangeable from time to time, in its discretion, for common units (that is, one OpCo unit and one Class B unit, together, are exchangeable for one common unit), and, as a result, Diamondback may be deemed to have the beneficial ownership of such common units. Diamondback has sole voting and dispositive power with respect to the common units and Class B units it holds. The directors of Diamondback are Travis D. Stice, Steven E. West, Vincent K. Brooks, Michael P. Cross, David L. Houston, Stephanie K. Mains, Mark L. Plaumann and Melanie M. Trent. Travis D. Stice is the sole director of Diamondback E&P.

(3) Based solely on Schedule 13D/A filed with the SEC on January 11, 2022. Represents common units held directly by BX Guidon Topco LLC ("BX Topco"). Guidon Energy Holdings LP is the managing member of Swallowtail Royalties LLC. The controlling membership interests of BX Topco are held by Blackstone Management Associates VI L.L.C. and Blackstone Energy Management Associates II L.L.C. BMA VI L.L.C. is the sole member of Blackstone Management Associates VI L.L.C. Blackstone EMA II L.L.C. is the sole member of Blackstone Energy Management Associates II L.L.C. Blackstone Holdings III L.P. is the managing member of each of BMA VI L.L.C. and Blackstone EMA II L.L.C. Blackstone Holdings III GP L.P. is the general partner of Blackstone Holdings III L.P. Blackstone Holdings III GP Management L.L.C. is the general partner of Blackstone Holdings III GP L.P. Blackstone Inc. is the sole member of Blackstone Holdings III GP Management L.L.C. The sole holder of the Series II preferred stock of Blackstone Inc. is Blackstone Group Management L.L.C. Blackstone Group Management L.L.C. is wholly-owned by Blackstone's senior managing directors and controlled by its founder, Stephen A. Schwarzman. Each of the above entities or persons may be deemed to beneficially own common units beneficially owned by BX Topco or indirectly controlled by such entity or person. Each of the above entities or persons disclaims beneficial ownership of such securities in excess of their respective pecuniary interest therein.

(4) Based solely on Schedule 13G/A jointly filed with the SEC on February 4, 2021 by Wellington Management Group LLP ("Wellington Management"), Wellington Group Holdings LLP ("Wellington Holdings"), Wellington Investment Advisors Holdings LLP ("Wellington Advisors") and Wellington Management Company LLP ("Wellington Company"). These units are owned of record by clients of Wellington Company, Wellington Management Canada LLC, Wellington Management Singapore Pte Ltd, Wellington Management Hong Kong Ltd, Wellington Management International Ltd, Wellington Management Japan Pte Ltd and Wellington Management Australia Pty Ltd (collectively, the "Wellington Investment Advisers"). Wellington Advisors controls directly, or indirectly through Wellington Management Global Holdings Ltd., the Wellington Investment Advisers. Wellington Advisors is owned by Wellington Holdings, which is in

turn owned by Wellington Management. The clients of the Wellington Investment Advisers have the right to receive, or the power to direct the receipt of, dividends from, or the proceeds from the sale of, such securities. No such client is known to have such right or power with respect to more than five percent of this class of securities. Each of Wellington Management, Wellington Holdings and Wellington Advisors reported shared voting power over 8,746,556 common units and shared dispositive power over 9,642,118 common units. Wellington Company reported shared voting power over 8,667,707 common units and shared dispositive power over 9,498,077 common units.

(5) Based on Viper's records.

Securities Authorized For Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2021:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans not approved by security holders[(1)]			
Long Term Incentive Plan	136,879	$ —	8,591,015

(1) Our General Partner adopted the LTIP in connection with the IPO in June 2014.

Changes in Control

Our General Partner may transfer its general partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owner of our General Partner to transfer its membership interests in our General Partner to a third party. After any such transfer, the new member or members of our General Partner would then be in a position to replace the board of directors and executive officers of our General Partner with its own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our General Partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

Treatment of Equity Awards Granted under the LTIP Upon Termination, Resignation and Death or Disability of Certain Executive Officers of our General Partner and Change of Control

No executive officers of our General Partner held unvested equity awards under the LTIP as of December 31, 2021.

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

Agreements and Transactions with Affiliates

We have entered into certain agreements and transactions with Diamondback and its affiliates, as described in more detail below.

Payments to our General Partner and its Affiliates

Under the terms of our partnership agreement, we are required to reimburse our General Partner for all direct and indirect expenses incurred or paid on our behalf and all other expenses allocable to us or otherwise incurred by our General Partner in connection with operating our business. The partnership agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Our General Partner is entitled to determine the expenses that are allocable to us. For the year ended December 31, 2021, our General Partner received $3.7 million in reimbursements from the Partnership.

Distributions paid to Diamondback

Diamondback is entitled to receive its pro rata portion of the distributions we make on our common units and the Operating Company makes in respect of the OpCo units. Holders of the Partnership's Class B units are not entitled to receive cash distributions except to the extent of the cash preferred distributions equal to 8% per annum payable quarterly on the $1.0 million capital contribution made to us by Diamondback pursuant to the recapitalization agreement in connection with the issuance of the Class B units in the recapitalization transaction. During the year ended December 31, 2021, Diamondback received distributions from us and the Operating Company in the aggregate amount of $100.7 million.

Registration Rights Agreement

On June 23, 2014, in connection with the IPO, we entered into a registration rights agreement with Diamondback. Pursuant to this registration rights agreement, we filed a registration statement on Form S-3 registering, under the Securities Act, the common units issued to Diamondback for resale. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution and allocation of expenses. These registration rights are transferable to affiliates and, in certain circumstances, to third parties.

In connection with our previously reported recapitalization transaction completed in May 2018, we and Diamondback entered into an amended and restated registration rights agreement, dated as of May 9, 2018, which amended and restated our original registration rights agreement with Diamondback entered into on June 23, 2014 in connection with our IPO. The amended and restated registration rights agreement amended the definition of "registrable securities" to include common units acquired or that may be acquired by Diamondback in accordance with our exchange agreement with Diamondback. In addition, whenever a holder has requested that any registrable securities be registered under the amended and restated registration rights agreement or has initiated an underwritten offering, the amended and restated registration rights agreement requires such holder, if applicable, to cause such registrable securities to be exchanged into common units in accordance with the terms of the exchange agreement before or substantially concurrently with the sale of such registrable securities.

In July 2018, we filed a registration statement on Form S-3ASR pursuant to which, among other things, in accordance with the amended and restated registration rights agreement, we registered for resale by Diamondback (i) common units issuable to Diamondback upon exercise by Diamondback of its exchange right pursuant to the exchange agreement and Diamondback's tender to us of an equivalent number of our outstanding Class B units and outstanding OpCo Units, in each case then held by Diamondback and (ii) common units then held by Diamondback.

Tax Sharing Agreement

In connection with the closing of the IPO, we entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which we agreed to reimburse Diamondback for our share of state and local income and other taxes for which our results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax that we would have paid had we not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe less or no tax. In such a situation, we agreed to reimburse Diamondback for the tax we would have owed had the tax attributes not been available or used for our benefit, even though Diamondback had no cash tax expense for that period. For the year ended December 31, 2021, we accrued $0.3 million of state income tax expense.

Lease Bonus Payments

During the year ended December 31, 2021, Diamondback paid us $1.3 million in lease bonus payments for two new leases.

Surface Use

Diamondback periodically pays us for surface use charges and right of way easements related to properties that Diamondback leases from us. During the year ended December 31, 2021, Diamondback paid the Partnership $0.6 million for such purposes.

Transaction with Significant Unitholder

On January 13, 2022, as part of our common unit repurchase program, we purchased 1.5 million common units with an aggregate purchase price of approximately $37.3 million in a privately negotiated transaction with an affiliate of Blackstone, Inc., or Blackstone. Immediately following this transaction, Blackstone beneficially owned approximately 17.5% of Viper's outstanding common units, which were acquired in the Swallowtail Acquisition. An affiliate of Blackstone also beneficially owns approximately 6.0% of the outstanding common stock of Diamondback.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

The board of directors of our General Partner has adopted policies for the review, approval and ratification of transactions with related persons. The board has adopted a written code of business conduct and ethics, under which a director is expected to bring to the attention of the chief executive officer or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our General Partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our General Partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the board of directors of our General Partner in accordance with the provisions of our partnership agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

Any executive officer is required to avoid conflicts of interest unless approved by the board of directors of our General Partner.

The code of business conduct and ethics described above was initially adopted in connection with the closing of the IPO as a result, the transactions described above that were effective at the time of the IPO were not reviewed according to such procedures.

Director Independence

The information required by Item 407(a) of Regulation S-K is included in "Item 10. Directors, Executive Officers and Corporate Governance" above.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The audit committee of the board of directors of our General Partner selected Grant Thornton LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the years ended December 31, 2021 and 2020. The audit committee's charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fees categories below with respect to our annual reports for the years ended December 31, 2021 and 2020 were approved by the audit committee.

The following table summarizes the aggregate Grant Thornton LLP fees that were allocated to us for independent auditing, tax and related services:

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Audit fees(1)	$ 331	$ 264
Audit-related fees(2)	84	—
Tax fees(3)	—	—
All other fees(4)	—	—
Total	$ 415	$ 264

(1) Audit fees represent aggregate fees for audit services, which relate to the fiscal year consolidated audit, quarterly reviews, registration statements and comfort letters.
(2) Audit-related fees represent fees for an acquired business audit required pursuant to Regulation S-X, Rule 3-05.
(3) Tax fees represent amounts billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning.
(4) All other fees represent amounts billed in each of the years presented for services not classifiable under the other categories listed in the table above.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

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 Partnership's consolidated financial statements and related notes.

3. Exhibits

Exhibit Number	Description
2.1#	Purchase and Sale Agreement dated August 6, 2021 by and among Swallowtail Royalties LLC, Swallowtail Royalties II LLC (collectively, as seller), Viper Energy Partners LLC (as buyer) and Viper Energy Partners LP (as parent, and collectively with Viper Energy Partners LLC, as buyer parties) (incorporated by reference to Exhibit 2.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on August 12, 2021).
3.1	Certificate of Limited Partnership of Viper Energy Partners LP (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement on Form S-1 (File No. 333-195769) filed on May 7, 2014).
3.2	Second Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP, dated as of May 9, 2018, as amended as of May 10, 2018 (incorporated by reference to 3.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018)
3.3	First Amendment to Second Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP, dated as of May 10, 2018. (incorporated by reference to Exhibit 3.2 of the Partnership's Current Report on Form 8-K, (File 001-36505) filed on May 15, 2018).
3.4	Second Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, dated as of May 9, 2018 (incorporated by reference to Exhibit 3.3 of the Partnership's Current Report on Form 8-K (File 001-36505), filed on May 15, 2018).
3.5	First Amendment to Second Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, dated as of March 30, 2020, (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on March 31, 2020).
3.6	Second Amendment to the Second Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, dated as of December 27, 2021 (incorporated by reference to 3.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on December 28, 2021).
4.1	Description of Securities of the Partnership (incorporated by reference to Exhibit 4.1 to the Partnership's Annual Report on Form 10-K (File 001-36505) filed on February 18, 2020).
4.2	Amended and Restated Registration Rights Agreement, dated as of May 9, 2018, by and between Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
4.3	Registration Rights Agreement, dated as of October 1, 2021, by and among Viper Energy Partners LP, Swallowtail Royalties LLC and Swallowtail Royalties II LLC (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 7, 2021).
4.4	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 the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).

Exhibit Number	Description
10.1	Amended and Restated Credit Agreement, dated as of July 20, 2018, by and among, Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on July 26, 2018).
10.2+	Viper Energy Partners LP Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.3	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.4	Tax Sharing Agreement, dated June 23, 2014, by and between Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.5 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.5+	Form of Unit Option Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.6+	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Annual Report on Form 10-K (File No. 001-36505) filed on February 18, 2020).
10.7	Recapitalization Agreement, dated as of March 28, 2018, by and among Diamondback Energy, Inc., Viper Energy Partners LLC, Viper Energy Partners GP LLC and Viper Energy Partners LP (incorporated by reference to Annex C to the Partnership's Definitive Information Statement on Schedule 14C (File No. 001-36505) filed on April 17, 2018).
10.8	First Amendment to Recapitalization Agreement dated as of May 9, 2018, by and among Diamondback Energy, Inc., Viper Energy Partners LLC, Viper Energy Partners GP LLC and Viper Energy Partners LP. (incorporated by reference to Exhibit 10.4 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
10.9	Exchange Agreement, dated as of May 9, 2018, by and among Diamondback Energy, Inc., Viper Energy Partners LLC, Viper Energy Partners GP LLC and Viper Energy Partners LP. (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
10.10	First Amendment to Exchange Agreement, dated as of May 10, 2018, by and among Diamondback Energy, Inc., Viper Energy Partners LLC, Viper Energy Partners GP LLC and Viper Energy Partners LP. (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
10.11	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on September 30, 2019).
10.12	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 10, 2019).
10.13	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).
10.14	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).
10.15	Sixth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 6, 2020, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on November 12, 2020).
10.16	Seventh Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of June 2, 2021, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on June 8, 2021).

Exhibit Number	Description
10.17	Eighth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement and Second Amendment to Guaranty and Collateral Agreement, dated as of November 15, 2021, by and among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on November 18, 2021).
10.18	Subordinated Promissory Note, dated as of October 16, 2019, by Viper Energy Partners LLC in favor of Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
21.1*	List of Subsidiaries of Viper Energy Partners LP.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, LP.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Reserve Report of Ryder Scott Company, L.P.
101	The following financial information from the Registrant'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 Unitholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to Consolidated Financial Statements.
104.0	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Filed herewith.

\+ Management contract, compensatory plan or arrangement.

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

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

ITEM 16 FORM 10-K SUMMARY

None.

SIGNATURES

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

VIPER ENERGY PARTNERS LP

Date: February 24, 2022

By: VIPER ENERGY PARTNERS GP LLC
its General Partner

By: /s/ Travis D. Stice
Name: Travis D. Stice
Title: Chief Executive Officer

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

Signature	Title	Date
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2022
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)	February 24, 2022
/s/ Steven E. West Steven E. West	Director	February 24, 2022
/s/ W. Wesley Perry W. Wesley Perry	Director	February 24, 2022
/s/ Spencer D. Armour Spencer D. Armour	Director	February 24, 2022
/s/ James L. Rubin James L. Rubin	Director	February 24, 2022
/s/ Rosalind Redfern Grover Rosalind Redfern Grover	Director	February 24, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
Viper Energy Partners LP

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Viper Energy Partners LP (a Delaware limited partnership) and subsidiary (the "Partnership") as of December 31, 2021 and 2020, the related consolidated statements of operations, unitholders' 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 Partnership 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 Partnership'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 Partnership's management. Our responsibility is to express an opinion on the Partnership'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 Partnership 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 Swallowtail Acquisition

As described in Note 2 to the financial statements, the Partnership 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 Partnership entered into a significant acquisition of mineral and royalty interests from the Swallowtail entities during the year. 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 operator's development plan for proved undeveloped properties. Management also utilizes an estimated fair value pricing model for the valuation of acquired proved producing 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 as 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 Partnership's proved reserves could have a significant impact on the measurement of depletion expense or impairment expense, and the fair value of the 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, assessing the Partnership's oil and gas properties for potential impairment, and management's estimation of the fair value of the acquired mineral and royalty interests. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Partnership'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 report of the acquired mineral and royalty interests prepared by the Partnership's specialists.
- We evaluated the level of knowledge, skill, and ability of the Partnership's reservoir engineering specialists and their relationship to the Partnership, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Partnership's proved reserve volumes, and read the reserve report prepared by the Partnership'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 Partnership's accounting records, such as historical pricing differentials and ownership 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 net revenue interests used in the reserve report by inspecting a sample of land and division order records;
    - Evaluated the Partnership's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the operator'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; 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:
    - Compared the fair value pricing used in the acquisition reserve report to published product pricing on the acquisition close date;
    - Inspected, on a sample basis, the net revenue interests used in the acquisition reserve report to land and division order records;
    - Analyzed, on a sample basis, 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 Partnership's auditor since 2013.
Oklahoma City, Oklahoma
February 24, 2022

Viper Energy Partners LP
Consolidated Balance Sheets

	December 31,	
	2021	2020
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 39,448	$ 19,121
Royalty income receivable (net of allowance for credit losses)	68,568	32,210
Royalty income receivable—related party	2,144	1,998
Other current assets	989	665
Total current assets	111,149	53,994
Property:		
Oil and natural gas interests, full cost method of accounting ($1,640,172 and $1,364,906 excluded from depletion at December 31, 2021 and December 31, 2020, respectively)	3,513,590	2,895,542
Land	5,688	5,688
Accumulated depletion and impairment	(599,163)	(496,176)
Property, net	2,920,115	2,405,054
Other assets	2,757	2,327
Total assets	$ 3,034,021	$ 2,461,375
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable	$ 69	$ 43
Accrued liabilities	20,980	18,262
Derivative instruments	3,417	26,593
Total current liabilities	24,466	44,898
Long-term debt, net	776,727	555,644
Total liabilities	801,193	600,542
Commitments and contingencies (Note 12)		
Unitholders' equity:		
General Partner	729	809
Common units (78,546,403 units issued and outstanding as of December 31, 2021 and 65,817,281 units issued and outstanding as of December 31, 2020)	813,161	633,415
Class B units (90,709,946 units issued and outstanding December 31, 2021 and December 31, 2020)	931	1,031
Total Viper Energy Partners LP unitholders' equity	814,821	635,255
Non-controlling interest	1,418,007	1,225,578
Total equity	2,232,828	1,860,833
Total liabilities and unitholders' equity	$ 3,034,021	$ 2,461,375

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Consolidated Statements of Operations

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per unit amounts)		
Operating income:			
Royalty income	$ 501,534	$ 246,981	$ 293,811
Lease bonus income	2,763	2,585	4,117
Other operating income	620	1,060	355
Total operating income	504,917	250,626	298,283
Costs and expenses:			
Production and ad valorem taxes	32,558	19,844	19,076
Depletion	102,987	100,501	78,178
Impairment	—	69,202	—
General and administrative expenses	7,800	8,165	7,489
Total costs and expenses	143,345	197,712	104,743
Income (loss) from operations	361,572	52,914	193,540
Other income (expense):			
Interest expense, net	(34,044)	(33,000)	(21,076)
Gain (loss) on derivative instruments, net	(69,409)	(63,591)	—
Gain (loss) on revaluation of investment	—	(8,556)	4,832
Other income, net	79	1,286	2,332
Total other expense, net	(103,374)	(103,861)	(13,912)
Income (loss) before income taxes	258,198	(50,947)	179,628
Provision for (benefit from) income taxes	1,521	142,466	(41,582)
Net income (loss)	256,677	(193,413)	221,210
Net income (loss) attributable to non-controlling interest	198,738	(1,109)	174,929
Net income (loss) attributable to Viper Energy Partners LP	$ 57,939	$ (192,304)	$ 46,281
Net income (loss) attributable to common limited partner units:			
Basic	$ 0.85	$ (2.84)	$ 0.75
Diluted	$ 0.85	$ (2.84)	$ 0.75
Weighted average number of common limited partner units outstanding:			
Basic	68,319	67,686	61,744
Diluted	68,391	67,686	61,787

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Statement of Consolidated Unitholders’ Equity

	Limited Partners				General Partner	Non-Controlling Interest	
	Common Units	Amount	Class B Units	Amount	Amount	Amount	Total
				(In thousands)			
Balance at December 31, 2018	51,654	$ 540,112	72,419	$ 990	$ 1,000	$ 694,940	$ 1,237,042
Net proceeds from the issuance of common units - public	10,925	340,860	—	—	—	—	340,860
Common units issued for acquisition	5,152	124,012		—	—	—	124,012
Offering costs	—	(221)		—	—	—	(221)
Unit-based compensation	—	1,822	—	—	—	—	1,822
Issuance of common units, net	75	—	—	—	—	—	—
Class B and OpCo units issued for the Drop-Down acquisition	—	—	18,291	250	—	497,162	497,412
Distributions to public	—	(107,074)	—	—	—	—	(107,074)
Distributions to Diamondback	—	(1,300)	—	(110)	—	(131,801)	(133,211)
Distributions to General Partner	—	31	—	—	(111)	—	(80)
Change in ownership of consolidated subsidiaries, net	—	(15,054)	—	—	—	19,055	4,001
Cash paid for tax withholding on vested common units	—	(353)	—	—	—	—	(353)
Net income (loss)	—	46,281	—	—	—	174,929	221,210
Balance at December 31, 2019	67,806	929,116	90,710	1,130	889	1,254,285	2,185,420
Unit-based compensation	—	1,272	—	—	—	—	1,272
Issuance of common units, net	56	—	—	—	—	—	—
Distribution equivalent rights payments	—	(44)	—	—	—	—	(44)
Distributions to public	—	(45,630)	—	—	—	—	(45,630)
Distributions to Diamondback	—	(498)	—	(99)	—	(61,685)	(62,282)
Distributions to General Partner	—	—	—	—	(80)	—	(80)
Change in ownership of consolidated subsidiaries, net	—	(34,087)	—	—	—	34,087	—
Cash paid for tax withholding on vested common units	—	(384)	—	—	—	—	(384)
Repurchased units as part of unit buyback	(2,045)	(24,026)	—	—	—	—	(24,026)
Net income (loss)	—	(192,304)	—	—	—	(1,109)	(193,413)
Balance at December 31, 2020	65,817	$ 633,415	90,710	$ 1,031	$ 809	$ 1,225,578	$ 1,860,833

See accompanying notes to consolidated financial statements.

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

	Limited Partners				General Partner	Non-Controlling Interest	
	Common Units	Amount	Class B Units	Amount	Amount	Amount	Total
				(In thousands)			
Balance at December 31, 2020	65,817	$ 633,415	90,710	$ 1,031	$ 809	$ 1,225,578	$ 1,860,833
Unit-based compensation	—	1,172	—	—	—	—	1,172
Common units issued for acquisition	15,250	336,872	—	—	—	—	336,872
Issuance of common units, net	92	—	—	—	—	—	—
Distribution equivalent rights payments	—	(193)	—	—	—	—	(193)
Distributions to public	—	(75,749)	—	—	—	—	(75,749)
Distributions to Diamondback	—	(803)	—	(100)	—	(99,782)	(100,685)
Distributions to General Partner	—	—	—	—	(80)	—	(80)
Change in ownership of consolidated subsidiaries, net	—	(93,473)	—	—	—	93,473	—
Cash paid for tax withholding on vested common units	—	(20)	—	—	—	—	(20)
Repurchased units as part of unit buyback	(2,613)	(45,999)	—	—	—	—	(45,999)
Net income (loss)	—	57,939	—	—	—	198,738	256,677
Balance at December 31, 2021	78,546	$ 813,161	90,710	$ 931	$ 729	$ 1,418,007	$ 2,232,828

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2021	2020	2019
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 256,677	$ (193,413)	$ 221,210
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax expense (benefit)	—	142,466	(41,582)
Depletion	102,987	100,501	78,178
Impairment	—	69,202	—
(Gain) loss on derivative instruments, net	69,409	63,591	—
Net cash receipts (payments) on derivatives	(92,585)	(36,998)	—
(Gain) loss on revaluation of investment	—	8,556	(4,832)
Other	4,710	3,589	2,800
Changes in operating assets and liabilities:			
Royalty income receivable	(36,358)	25,879	(19,266)
Royalty income receivable—related party	(146)	8,578	(7,087)
Other	2,420	4,605	7,270
Net cash provided by (used in) operating activities	307,114	196,556	236,691
Cash flows from investing activities:			
Acquisitions of oil and natural gas interests	(281,176)	(65,678)	(530,572)
Proceeds from sale of assets	—	38,594	—
Proceeds from the sale of investments	—	10,801	—
Net cash provided by (used in) investing activities	(281,176)	(16,283)	(530,572)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	330,000	104,000	590,500
Repayment on credit facility	(110,000)	(116,500)	(905,000)
Proceeds from senior notes	—	—	500,000
Repayment of senior notes	—	(19,697)	—
Debt issuance costs	(2,885)	(111)	(10,863)
Proceeds from public offerings	—	—	340,860
Repurchased units as part of unit buyback	(45,999)	(24,026)	—
Distributions to public	(75,942)	(45,674)	(107,074)
Distributions to Diamondback	(100,685)	(62,282)	(133,211)
Other	(100)	(464)	(405)
Net cash provided by (used in) financing activities	(5,611)	(164,754)	274,807
Net increase (decrease) in cash and cash equivalents	20,327	15,519	(19,074)
Cash, cash equivalents and restricted cash at beginning of period	19,121	3,602	22,676
Cash, cash equivalents and restricted cash at end of period	$ 39,448	$ 19,121	$ 3,602
Supplemental disclosure of cash flow information:			
Interest paid	$ 30,784	$ 33,121	$ 13,803
Supplemental disclosure of non—cash transactions:			
OpCo units issued for the Drop-Down transaction	$ —	$ —	$ 497,162
Common units issued for acquisition	$ 336,872	$ —	$ 124,012

See accompanying notes to consolidated financial statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Viper Energy Partners LP (the “Partnership”) is a publicly traded Delaware limited partnership focused on owning and acquiring mineral interests and royalty interests in oil and natural gas properties primarily in the Permian Basin.

As of December 31, 2021, Viper Energy Partners GP LLC (the “General Partner”), held a 100% general partner interest in the Partnership and Diamondback beneficially owned an approximate 54% of the Partnership’s total limited partner units outstanding. Diamondback owns and controls the General Partner.

Basis of Presentation

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

Reclassifications

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

Making accurate estimates and assumptions is particularly difficult in the oil and natural gas industry given the challenges resulting from volatility in oil and natural gas prices. For instance, in 2020, the effects of COVID-19 and actions by OPEC members and other exporting nations on the supply and demand in global oil and natural gas markets resulted in significant negative pricing pressure in the first half of 2020, followed by a recovery in pricing and an increase in demand in the second half of 2020 and into 2021. However, the COVID-19 Delta variant emerged in March 2021 and became highly transmissible in July 2021, and the Omicron variant emerged in November 2021, which contributed to additional pricing volatility during the fourth quarter of 2021. The financial results of companies in the oil and natural gas industry have been impacted materially as a result of changing market conditions. Such circumstances generally increase uncertainty in the Partnership’s accounting estimates, particularly those involving financial forecasts.

The Partnership evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Partnership considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Partnership’s estimates. Any effects on the Partnership’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, but are not limited to, 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 recoverability of costs of unevaluated properties, the fair value determination of assets and liabilities, including those acquired by the Partnership, fair value estimates of commodity derivatives and estimates of income taxes.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and include all highly liquid investments purchased with a maturity of three months or less and money market funds. The Partnership maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Partnership has not experienced any significant losses from such investments.

Accounts Receivable

Accounts receivable consist of receivables from oil and natural gas sales. The operators remit payment for production directly to the Partnership. Most payments for production are received within three months after the production date. Payments on new wells added organically or through acquisition may be further delayed due to title opinion work which is required to be completed by the operator before payments are released.

The Partnership 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 purchasers, net of an allowance for expected losses as estimated by the Partnership when collection is deemed doubtful. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Partnership determines its allowance by considering a number of factors, including the Partnership's previous loss history, the debtor's current ability to pay its obligation to the Partnership, the condition of the general economy and the industry as a whole. The Partnership writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for expected losses. The adoption of ASU 2016-13 did not result in a material change to the Partnership's allowance, and no cumulative-effect adjustment was made to beginning unitholders' equity. At December 31, 2021 and December 31, 2020, the Partnership's allowance for expected losses was immaterial.

Derivative Instruments

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

Revenue from Contracts with Customers

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

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

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

Transaction price allocated to remaining performance obligations

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

Contract balances

Under the Partnership’s royalty income contracts, it would have the right to receive royalty income from the producer once production has occurred, at which point payment is unconditional. Accordingly, the Partnership’s royalty income contracts do not give rise to contract assets or liabilities under Accounting Standards Codification 606.

Prior-period performance obligations

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

Oil and Natural Gas Properties

The Partnership 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. All internal costs not directly associated with exploration and development activities were charged to expense as they were 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 liquids and natural gas. At December 31, 2021 and 2020, the Partnership’s oil and natural gas properties consist solely of mineral interests in oil and natural gas properties.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $10.04, $10.34 and $9.95 for the years ended December 31, 2021, 2020 and 2019, respectively. Depletion for oil and natural gas properties was $103.0 million, $100.5 million and $78.2 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Under the full cost method of accounting, the Partnership 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. See Note 5—Oil and Natural Gas Interests for additional discussion of our oil and natural gas properties.

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

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $9.6 million and $6.7 million, and accumulated amortization of those costs over the term of the credit agreement of $6.8 million and $4.4 million as of December 31, 2021, and 2020, respectively.

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

Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2021	2020
	(In thousands)	
Interest payable	$ 4,430	$ 4,311
Ad valorem taxes payable	6,201	6,501
Derivatives instruments payable	8,879	7,392
Other	1,470	58
Total accrued liabilities	$ 20,980	$ 18,262

Concentrations

The Partnership is subject to risk resulting from the concentration of the Partnership's royalty interest revenue in producing oil and natural gas properties and receivables with several significant purchasers. For the year ended December 31, 2021, three purchasers each accounted for more than 10% of royalty interest revenue: Trafigura Trading LLC (17%), Shell Trading (US) Company ("Shell Trading") (16%) and Vitol Midstream Pipeline LLC (12%). For the year ended December 31, 2020, four purchasers each accounted for more than 10% of royalty interest revenue: Trafigura Trading LLC (23%), Vitol Midstream Pipeline LLC (14%), Shell Trading (13%) and Concho Resources (11%). For the year ended December 31, 2019, three purchasers each accounted for more than 10% of royalty interest revenue: Trafigura Trading LLC (27%), Concho Resources (16%) and Shell Trading (12%). The Partnership does not require collateral and does not believe the loss of any single purchaser would materially impact the Partnership's operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Income Taxes

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

The Partnership 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, 2020 and 2019, there was no interest or penalties associated with uncertain tax positions recognized in the Partnership's consolidated financial statements. See Note 9—Income Taxes for further details.

Non-controlling Interest

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

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 Partnership 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

There are no recent accounting pronouncements not yet adopted.

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

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

For the years ended December 31, 2021, 2020 and 2019, any revenues recognized in the current reporting period for performance obligations satisfied in prior reporting periods was not material.

The following table disaggregates the Partnership's total royalty income by product type:

	Year Ended December 31,		
	2021	**2020**	**2019**
		(In thousands)	
Oil income	$ 397,513	$ 217,859	$ 264,376
Natural gas income	49,197	9,024	8,092
Natural gas liquids income	54,824	20,098	21,343
Total royalty income	$ 501,534	$ 246,981	$ 293,811

4. ACQUISITIONS AND DIVESTITURES

2021 Activity

Swallowtail Acquisition

On October 1, 2021, the Partnership and the Operating Company acquired certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC (the “Swallowtail entities”) pursuant to a definitive purchase and sale agreement for approximately 15.25 million common units and approximately $225.3 million in cash (the “Swallowtail Acquisition”). The mineral and royalty interests acquired in the Swallowtail Acquisition represent 2,313 net royalty acres primarily in the Northern Midland Basin, of which 62% are operated by Diamondback. The Swallowtail Acquisition has an effective date of August 1, 2021. In accordance with the terms of the purchase agreement, the Partnership deposited $30.0 million into an escrow account in August 2021, which was released upon the closing of the transaction. The cash portion of this transaction was funded through a combination of cash on hand and approximately of $190.0 million borrowings under the Operating Company’s revolving credit facility.

Other 2021 Acquisitions

Additionally during the year ended December 31, 2021, the Partnership acquired, from unrelated third party sellers, mineral and royalty interests representing 1,277 gross (392 net royalty) acres in the Permian Basin for an aggregate purchase price of approximately $55.1 million, after post-closing adjustments. The Partnership funded these acquisitions with cash on hand and borrowings under the Operating Company’s revolving credit facility.

2020 Acquisitions

During the year ended December 31, 2020, the Partnership 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 $64.2 million, after post-closing adjustments. The Partnership funded these acquisitions with cash on hand and borrowings under the Operating Company’s revolving credit facility.

2019 Activity

Drop-Down Acquisition

On October 1, 2019, the Partnership completed the acquisition of certain mineral and royalty interests from subsidiaries of Diamondback for approximately 18.3 million of its newly-issued Class B units, approximately 18.3 million newly-issued units of the Operating Company with a fair value of $497.2 million and $190.2 million in cash, after giving effect to closing adjustments for net title benefits (the ‘‘Drop-Down Acquisition’’). The mineral and royalty interests acquired in the Drop-Down Acquisition represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by Diamondback, and have an average net royalty interest of approximately 3.2% (the ‘‘Drop-Down Assets’’). The Partnership completed the acquisition on October 1, 2019 and funded the cash portion of the purchase price for the Drop-Down Assets through a combination of cash on hand and borrowings under the Operating Company’s revolving credit facility.

Santa Elena Acquisition

On October 31, 2019, the Partnership completed the acquisition of certain mineral and royalty interests from Santa Elena (the ‘‘Santa Elena Acquisition’’), which assets were immediately contributed by the Partnership to the Operating Company. The assets acquired in the Santa Elena Acquisition represent approximately 1,366 net royalty acres across the Midland Basin with an average net royalty interest of approximately 5.6% and are primarily operated by Diamondback in Glasscock and Martin counties (the ‘‘Santa Elena Assets’’).

At closing, the Partnership issued to Santa Elena approximately 5.2 million common units representing limited partner interests in the Partnership as consideration for the Santa Elena Assets, and the Operating Company issued to the Partnership approximately 5.2 million new units of the Operating Company with a fair value of $124.0 million.

Other 2019 Acquisitions

In addition, during the year ended December 31, 2019, the Partnership acquired, from unrelated third party sellers, mineral interests representing 136,012 gross (2,607 net royalty) acres for an aggregate of approximately $343.7 million. The Partnership funded these acquisitions with cash on hand, a portion of the net proceeds from its first quarter 2019 offering of common units and borrowings under the Operating Company's revolving credit facility.

Divestitures of Certain Non-Core Assets and Investments

During 2020, the Partnership divested its equity interest in a limited partnership for approximately $10.8 million. This divestiture resulted in an immaterial loss.

During the year ended December 31, 2020, the Partnership completed its divestiture of 370 net royalty acres of certain non-core Permian assets for an aggregate sale price of $38.4 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Partnership's reserve base or depreciation, depletion and amortization rate.

5. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	December 31,	
	2021	2020
	(In thousands)	
Oil and natural gas interests:		
Subject to depletion	$ 1,873,418	$ 1,530,636
Not subject to depletion	1,640,172	1,364,906
Gross oil and natural gas interests	3,513,590	2,895,542
Accumulated depletion and impairment	(599,163)	(496,176)
Oil and natural gas interests, net	2,914,427	2,399,366
Land	5,688	5,688
Property, net of accumulated depletion and impairment	$ 2,920,115	$ 2,405,054
Balance of costs not subject to depletion:		
Incurred in 2021	$ 478,747	
Incurred in 2020	55,041	
Incurred in 2019	827,680	
Incurred in 2018	278,704	
Total not subject to depletion	$ 1,640,172	

As of December 31, 2021 and December 31, 2020, the Partnership had mineral and royalty interests representing 27,027 and 24,350 net royalty acres, respectively.

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

Based on the results of the quarterly ceiling tests, the Partnership was not required to record an impairment on our proved oil and natural gas interests for the years ended December 31, 2021 and 2019, respectively. The Partnership recorded an impairment expense of $69.2 million as a result of the decline in commodity prices for the year ended December 31, 2020. In addition to commodity prices, the Partnership's production rates, levels of proved reserves, transfers of unevaluated properties and other factors will determine its actual ceiling test limitations and impairment analysis in future periods. If the trailing 12-month commodity prices were to fall as compared to the commodity prices used in prior quarters, the Partnership will have write-downs in subsequent quarters, which may be material.

6. DEBT

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

	December 31, 2021	December 31, 2020
	(In thousands)	
5.375% senior unsecured notes due 2027	$ 479,938	$ 479,938
Revolving credit facility	304,000	84,000
Unamortized debt issuance costs	(1,757)	(2,058)
Unamortized discount	(5,454)	(6,236)
Total long-term debt	$ 776,727	$ 555,644

The Operating Company's Revolving Credit Facility

On June 2, 2021, the Operating Company 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, the Operating Company entered into the eighth amendment to the existing credit agreement, which maintained the maximum amount of the revolving credit facility at $2.0 billion, reaffirmed the borrowing base of $580.0 million based on the Operating Company's oil and natural gas reserves and other factors, and allowed the Operating Company 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, the Operating Company 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, the Operating Company had elected a commitment amount of $500.0 million, with $304.0 million of outstanding borrowings and $196.0 million available for future borrowings under the Operating Company's revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Operating Company that is equal to an alternative 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 alternative base rate and from 2.00% to 3.00% per annum in the case of LIBOR, in each case depending on the amount of the loans outstanding in relation to the commitment, which is calculated using the least of the maximum credit amount, the aggregate elected commitment amount and the borrowing base. The Operating Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, 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 LIBOR breakage), and is required to be repaid (a) 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), (b) 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 (c) at the maturity date. The loan is secured by substantially all the assets of the Partnership and the Operating Company. For the years ended December 31, 2021, 2020 and 2019, the weighted average interest rate on borrowings under the Operating Company's revolving credit facility was 2.35%, 2.20%, and 4.51%, respectively.

The 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 credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0
Ratio of secured debt to EBITDAX, as defined in the 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, the Operating Company was in compliance with all financial maintenance covenants under its credit agreement. The lenders may accelerate all of the indebtedness under the Operating Company's 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. 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.

7. UNITHOLDERS' EQUITY AND DISTRIBUTIONS

The Partnership has General Partner and limited partner units. At December 31, 2021, the Partnership had a total of 78,546,403 common units and 90,709,946 Class B units issued and outstanding, of which 731,500 common units and 90,709,946 Class B units were beneficially owned by Diamondback, representing approximately 54% of the Partnership's total units outstanding. Diamondback also beneficially owns 90,709,946 Operating Company units, representing a 54% non-controlling ownership interest in the Operating Company. The Operating Company units and the Partnership's Class B units beneficially owned by Diamondback are exchangeable from time to time for the Partnership's common units (that is, one Operating Company unit and one Partnership Class B unit, together, will be exchangeable for one Partnership common unit).

Common Unit Repurchase Program

The board of directors of the Partnership's general partner previously established a common unit repurchase program pursuant to which it was authorized to repurchase, in the open market or in privately negotiated transactions, its common units having the initial aggregate purchase price of up to $100.0 million and the initial term ending on December 31, 2021. Prior to the expiration of the initial repurchase program, the board of directors of the Partnership's general partner approved an increase to the common unit repurchase program to up to $150.0 million of the Partnership's outstanding common units and extended the authorization indefinitely. The increased repurchase program went into effect on November 15, 2021. During the years ended December 31, 2021 and 2020, the Partnership repurchased approximately $46.0 million and $24.0 million of common units under the repurchase program, respectively. As of December 31, 2021, $80.0 million remains available for use to repurchase units under the repurchase program. The Partnership intends to purchase common units under the repurchase program opportunistically with funds from cash on hand, free cash flow from operations and potential liquidity events such as the sale of assets. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors of the Partnership's General Partner at any time.

Changes in Ownership of Consolidated Subsidiaries

Non-controlling interest in the accompanying consolidated financial statements represents Diamondback's ownership in the net assets of the Operating Company. Diamondback's relative ownership interest in the Operating Company can change due to the Partnership's public offerings, issuance of units for acquisitions, issuance of unit-based compensation, repurchases of common units and distribution equivalent rights paid on the Partnership's units. These changes in ownership percentage and the disproportionate allocation of net income (loss) to Diamondback discussed below result in adjustments to non-controlling interest and common unitholder equity, tax effected, but do not impact earnings.

The following table summarizes the changes in common unitholder equity due to changes in ownership interest during the period:

	Year Ended December 31,		
	2021	2020	2019
	(In thousands)		
Net income (loss) attributable to the Partnership	$ 57,939	$ (192,304)	$ 46,281
Change in ownership of consolidated subsidiaries	(93,473)	(34,087)	(15,054)
Change from net income (loss) attributable to the Partnership's unitholders and transfers to non-controlling interest	$ (35,534)	$ (226,391)	$ 31,227

Cash Distributions

Beginning with the first quarter of 2020, the board of directors of the General Partner revised the distribution policy to provide that the Operating Company would distribute a percentage of its available cash to its unitholders (including Diamondback and the Partnership) rather than all of its available cash as it had previously done. The Partnership in turn distributes all of the available cash it receives from the Operating Company to its common unitholders. The Partnership's available cash, and the available cash of the Operating Company, for each quarter is determined by the board of directors of the General Partner following the end of such quarter. The Operating Company's available cash generally equals its Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations, fixed charges and reserves for future operating or capital needs that the board of directors of the General Partner deems necessary or appropriate, if any. The Partnership's available cash for each quarter generally equals its Adjusted EBITDA (which is the Partnership's proportional share of its available cash of the Operating Company for the quarter), less cash needed for the payment of income taxes by it, if any, and the preferred distribution. Immediately prior to the revisions to the distribution policy described above, the Operating Company's policy was to distribute all of its available cash quarterly to its unitholders. The distribution policy changes noted above were made to enable the Operating Company to retain cash flow to help strengthen the Partnership's balance sheet while also expanding the return of capital program through the Partnership's common unit repurchase program.

The board of directors of the General Partner may change the distribution policies at any time. The Partnership is not required to pay distributions to its common unitholders on a quarterly or other basis.

The following table presents cash distributions approved by the board of directors of the General Partner for the periods presented:

			Distributions (In thousands)				
Period	Amount per Unit	Percentage of Operating Company Available Cash Distributed	Operating Company Distributions to Diamondback	Common Unitholders(1)	Declaration Date	Unitholder Record Date	Payment Date
Q4 2018	$ 0.51	100 %	$ 36,934	$ 26,382	January 30, 2019	February 19, 2019	February 25, 2019
Q1 2019	$ 0.38	100 %	$ 27,519	$ 23,839	April 25, 2019	May 13, 2019	May 20, 2019
Q2 2019	$ 0.47	100 %	$ 34,036	$ 29,483	July 28, 2019	August 14, 2019	August 21, 2019
Q3 2019	$ 0.46	100 %	$ 33,312	$ 28,639	October 25, 2019	November 8, 2019	November 15, 2019
Q4 2019	$ 0.45	100 %	$ 40,819	$ 30,543	February 7, 2020	February 21, 2020	February 28, 2020
Q1 2020	$ 0.10	25 %	$ 9,074	$ 6,790	April 30, 2020	May 14, 2020	May 21, 2020
Q2 2020	$ 0.03	25 %	$ 2,720	$ 2,034	July 29, 2020	August 13, 2020	August 20, 2020
Q3 2020	$ 0.10	50 %	$ 9,072	$ 6,805	October 28, 2020	November 12, 2020	November 19, 2020
Q4 2020	$ 0.14	50 %	$ 12,699	$ 9,162	February 19, 2021	March 4, 2021	March 11, 2021
Q1 2021	$ 0.25	60 %	$ 22,678	$ 16,230	April 27, 2021	May 13, 2021	May 20, 2021
Q2 2021	$ 0.33	70 %	$ 29,936	$ 21,235	July 28, 2021	August 12, 2021	August 19, 2021
Q3 2021	$ 0.38	70 %	$ 34,469	$ 30,118	October 27, 2021	November 11, 2021	November 18, 2021

(1) Includes amounts paid to Diamondback for the 731,500 common units beneficially owned by Diamondback.

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

Allocation of Net Income

The Partnership, as managing member of the Operating Company, has entered into an agreement whereby special allocations of the Operating Company's income and gains over losses and deductions (but before depletion) are to be made to Diamondback. This agreement was amended in December 2021 to shorten the remaining period of special allocations to Diamondback by one year, so that the special allocation period will end on December 31, 2022, rather than on December 31, 2023. These special income allocations will reduce the taxable income allocated to the Partnership's common unitholders.

8. EARNINGS PER COMMON UNIT

The net income (loss) per common unit on the consolidated statements of operations is based on the net income (loss) of the Partnership for the years ended December 31, 2021, 2020 and 2019, since this is the amount of net income (loss) that is attributable to the Partnership's common units.

The Partnership's net income (loss) is allocated wholly to the common units, as the General Partner does not have an economic interest. Payments made to the Partnership's unitholders are determined in relation to the cash distribution policy described in Note 7—Unitholders' Equity and Partnership Distributions.

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

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

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per unit amounts)		
Net income (loss) attributable to the period	$ 57,939	$ (192,304)	$ 46,281
Less: net income (loss) allocated to participating securities[1]	193	(44)	(117)
Net income (loss) attributable to common unitholders	$ 58,132	$ (192,348)	$ 46,164
Weighted average common units outstanding:			
Basic weighted average common units outstanding	68,319	67,686	61,744
Effect of dilutive securities:			
Potential common units issuable[2]	72	—	43
Diluted weighted average common units outstanding	68,391	67,686	61,787
Net income (loss) per common unit, basic	$ 0.85	$ (2.84)	$ 0.75
Net income (loss) per common unit, diluted	$ 0.85	$ (2.84)	$ 0.75

(1) Distribution equivalent rights granted to employees are considered participating securities.

(2) For the year ended December 31, 2021, 10,160 potential common units were excluded from the computation of diluted earnings per common unit because their inclusion would have been anti-dilutive. For the year ended December 31, 2020, no potential common units were included in the computation of diluted earnings per common unit because their inclusion would have been anti-dilutive as a result of recording a net loss attributable to the common unitholders for the period.

9. INCOME TAXES

The Partnership's 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 net income attributable to the non-controlling interest and the impact of maintaining a valuation allowance on the Partnership's deferred tax assets. For the year ended December 31, 2020, total income tax expense differed from amounts computed by applying the United States federal statutory rate to pre-tax loss for the period primarily due to net loss attributable to the non-controlling interest and the impact of recording a valuation allowance on the Partnership's deferred tax assets. Total income tax benefit 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 net income attributable to the non-controlling interest and the revision of estimated deferred taxes recognized as a result of the Partnership's change in tax status.

The components of the provision for income taxes and effective tax rates for the years ended December 31, 2021, 2020 and 2019 are as follows:

	Year Ended December 31, 2021	2020	2019
	(In thousands)		
Current income tax provision (benefit):			
Federal	$ 1,218	$ —	$ —
State	303	—	—
Total current income tax provision (benefit)	1,521	—	—
Deferred income tax provision (benefit):			
Federal	—	142,466	(41,582)
State	—	—	—
Total deferred income tax provision (benefit)	—	142,466	(41,582)
Total provision (benefit) from income taxes	$ 1,521	$ 142,466	$ (41,582)
Effective tax rates	0.6 %	(279.6)%	(23.1)%

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

	Year Ended December 31, 2021	2020	2019
	(In thousands)		
Income tax expense (benefit) at the federal statutory rate (21%)	$ 54,221	$ (10,699)	$ 37,722
Impact of nontaxable noncontrolling interest	(41,735)	233	(36,735)
State income tax expense (benefit), net of federal tax effect	262	—	—
Deferred taxes related to change in tax status	—	—	(42,424)
Change in valuation allowance	(11,175)	152,898	—
Other, net	(52)	34	(145)
Provision for (benefit from) income taxes	$ 1,521	$ 142,466	$ (41,582)

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

	Year Ended December 31, 2021	2020
	(In thousands)	
Deferred tax assets:		
Net operating loss and interest expense carryforwards (indefinite life carryforward)	$ 6,014	$ 10,477
Investment in the Operating Company	163,065	150,127
Total deferred tax assets	169,079	160,604
Valuation allowance	(169,079)	(160,604)
Net deferred tax assets	—	—
Net deferred tax assets (liabilities)	$ —	$ —

As of December 31, 2021 and 2020, the Partnership had no net deferred tax assets or deferred tax liabilities. Subsequent to the Partnership’s change in tax status, deferred taxes are provided on the difference between the Partnership’s basis for financial accounting purposes and basis for federal income tax purposes in its investment in the Operating Company. At December 31, 2021, the Partnership had federal net operating loss carryforwards of approximately $28.6 million which may be carried forward indefinitely to offset future taxable income.

As of December 31, 2021, the Partnership had a valuation allowance of approximately $169.1 million related to deferred tax assets the Partnership does not believe are more likely than not to be realized. Management considers the likelihood that the Partnership's net operating losses 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 the Partnership'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 Partnership's assessment resulted in application of a valuation allowance against the Partnership's federal deferred tax assets as of March 31, 2020 and subsequent balance sheet dates within the years ended December 31, 2021 and 2020. In addition, a valuation allowance was maintained against state net operating loss carryforwards not anticipated to be utilized prior to expiration.

The Partnership principally operates in the state of Texas. For the years ended December 31, 2021, the Partnership accrued $0.3 million state income tax expenses for its share of Texas margin tax attributable to the Partnership's results which are included in a combined tax return filed by Diamondback. For the year ended December 31, 2020, the Partnership did not accrue any state income tax expenses. At December 31, 2021, the Partnership did not have any significant uncertain tax positions requiring recognition in the financial statements. In addition to the 2019 through 2021 tax years, our 2018 tax year during which we elected to be treated as a corporation for income tax purposes, remains open to examination by tax authorities.

The American Rescue Plan was enacted on March 11, 2021 and the Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") was enacted on March 27, 2020, which included a number of provisions applicable to U.S. income taxes for corporations. The Partnership considered the impact of this legislation in the period of enactment and concluded there was not a material impact to the Partnership's current or deferred income tax balances.

10. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Partnership has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

Commodity Contracts

During 2021, the Partnership used fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of its royalty income. Under the Partnership's costless collar contracts, each collar has an established floor price and ceiling price. When the settlement price is below the floor price, the counterparty is required to make a payment to the Partnership and when the settlement price is above the ceiling price, the Partnership is required to make a payment to the counterparty. When the settlement price is between the floor and the ceiling, there is no payment required.

The Partnership's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing (Cushing) and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub pricing.

By using derivative instruments to economically hedge exposure to changes in commodity prices, the Partnership 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 Partnership, which creates credit risk. The Partnership's counterparties are all participants in the amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Partnership is not required to post any collateral. The Partnership's counterparties have been determined to have an acceptable credit risk; therefore, the Partnership does not require collateral from its counterparties.

As of December 31, 2021, the Partnership had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

					Swaps		Collars		Puts
Settlement Month	Settlement Year	Type of Contract	Bbls/Mcf Per Day	Index	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Strike Price
OIL									
Jan. - Mar.	2022	Collars	2,500	WTI Cushing	$—	$—	$45.00	$79.55	$—
Apr. - Jun.	2022	Collars	2,000	WTI Cushing	$—	$—	$45.00	$80.15	$—
Jul. - Sep.	2022	Collars	4,000	WTI Cushing	$—	$—	$45.00	$92.65	$—
Jan. - Mar.	2022	Puts(1)	9,500	WTI Cushing	$—	$—	$—	$—	$47.51
Apr. - Jun.	2022	Puts(2)	8,000	WTI Cushing	$—	$—	$—	$—	$47.50
NATURAL GAS									
Jan. - Dec.	2022	Collars	20,000	Henry Hub	$—	$—	$2.50	$4.62	$—

(1) Includes a deferred premium at a weighted average price of $1.57/Bbl.
(2) Includes a deferred premium at a weighted average price of $1.55/Bbl.

Balance Sheet Offsetting of Derivative Assets and Liabilities

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

Gains and Losses on Derivative Instruments

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

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(In thousands)	
Gain (loss) on derivative instruments	$ (69,409)	$ (63,591)
Net cash receipts (payments) on derivatives	$ (92,585)	$ (36,998)

The Partnership did not have any derivatives prior to February 2020.

11. FAIR VALUE MEASUREMENTS

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

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Partnership'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 Partnership 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 Partnership's derivative instruments. The fair values of the Partnership's derivative contracts are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

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 Partnership's consolidated balance sheets as of December 31, 2021 and December 31, 2020. The net amounts 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 thousands)					
Assets:						
Current:						
Derivative instruments	$ —	$ 1,921	$ —	$ 1,921	$ (1,921)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 5,338	$ —	$ 5,338	$ (1,921)	$ 3,417

	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 thousands)					
Assets:						
Current:						
Derivative instruments	$ —	$ 2,340	$ —	$ 2,340	$ (2,340)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 28,933	$ —	$ 28,933	$ (2,340)	$ 26,593

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 thousands)			
Debt:				
Revolving credit facility	$ 304,000	$ 304,000	$ 84,000	$ 84,000
5.375% senior notes due 2027(1)	$ 472,727	$ 498,992	$ 471,644	$ 501,439

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

The fair value of the Operating Company's revolving credit facility approximates the carrying value based on borrowing rates available to the Partnership for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Notes was determined using the December 31, 2021 quoted market price, a Level 1 classification in the fair value hierarchy.

Fair Value of Financial Assets

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

12. COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various routine legal proceedings, disputes and claims from time to time 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. These proceedings, disputes and claims may include differing interpretations as to the prices at which crude oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, title claims, environmental issues and other matters. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on the Partnership, cannot be predicted with certainty, the Partnership's management believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Partnership's financial condition, results of operations or cash flows. The Partnership'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 Partnership's assessment. The Partnership records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

13. SUBSEQUENT EVENTS

Cash Distribution

On February 16, 2022, the board of directors of the General Partner approved a cash distribution for the fourth quarter of 2021 of $0.47 per common unit, payable on March 11, 2022, to unitholders of record at the close of business on March 4, 2022.

Repurchase of Units

On January 13, 2022, as part of our common unit repurchase program, the Partnership repurchased 1.5 million common units with an aggregate purchase price of approximately $37.3 million in a privately negotiated transaction with an affiliate of Blackstone. This was funded through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility and was accounted for under the cost method. The common units were immediately retired.

Divestiture

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

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

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

Capitalized oil and natural gas costs

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

	December 31,	
	2021	2020
	(In thousands)	
Oil and natural gas interests:		
Proved	$ 1,873,418	$ 1,530,636
Unproved	1,640,172	1,364,906
Total oil and natural gas interests	3,513,590	2,895,542
Accumulated depletion and impairment	(599,163)	(496,176)
Net oil and natural gas interests capitalized	$ 2,914,427	$ 2,399,366

Costs incurred in oil and natural gas activities

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

	December 31,		
	2021	2020	2019
	(In thousands)		
Acquisition costs:			
Proved properties	$ 138,882	$ 9,509	$ 318,525
Unproved properties	479,041	56,169	833,221
Total	$ 617,923	$ 65,678	$ 1,151,746

Results of Operations from Oil and Natural Gas Producing Activities

Substantially all of the Partnership's producing activities are from oil and natural gas activities and are included in the Consolidated Statements of Operations above.

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates 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 (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
		(In thousands)	
Proved Developed and Undeveloped Reserves:			
As of December 31, 2018	41,878	10,992	61,597
Purchase of reserves in place	12,949	4,895	24,423
Extensions and discoveries	11,526	3,095	14,822
Revisions of previous estimates	(6,810)	1,041	2,589
Production	(5,123)	(1,459)	(7,657)
As of December 31, 2019	54,420	18,564	95,774
Purchase of reserves in place	491	113	507
Extensions and discoveries	15,415	4,424	23,982
Revisions of previous estimates	(6,685)	763	11,043
Divestitures	(155)	(63)	(370)
Production	(5,956)	(1,848)	(11,486)
As of December 31, 2020	57,530	21,953	119,450
Purchase of reserves in place	5,246	2,264	9,549
Extensions and discoveries	17,256	7,182	39,256
Revisions of previous estimates	(4,544)	(1,339)	29,788
Divestitures	(180)	(114)	(681)
Production	(6,068)	(1,913)	(13,672)
As of December 31, 2021	69,240	28,033	183,690
Proved Developed Reserves:			
December 31, 2019	40,857	14,994	80,737
December 31, 2020	40,220	16,724	93,617
December 31, 2021	49,280	19,476	134,485
Proved Undeveloped Reserves:			
December 31, 2019	13,563	3,570	15,037
December 31, 2020	17,310	5,229	25,833
December 31, 2021	19,960	8,557	49,205

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 Partnership's total extensions and discoveries of 30,981 MBOE resulted primarily from the drilling of 407 new wells and from 336 new proved undeveloped locations added. The Partnership's total negative revisions of previous estimated quantities of 918 MBOE were due to PUD downgrades of 11,263 MBOE which were largely offset by positive revisions of 10,345 MBOE attributable to price and performance revisions. Total purchases of reserves in place of 9,102 MBOE resulted from multiple acquisitions of certain mineral and royalty interests, including the Swallowtail Acquisition.

During the year ended December 31, 2020, the Partnership's extensions and discoveries of 23,836 MBOE resulted primarily from the drilling of 652 new wells and from 299 new proved undeveloped locations added. The Partnership's negative revisions of previous estimated quantities of 4,082 MBOE were due to negative price revisions and PUD downgrades. 114 MBOE of PUDs were downgraded from non-operated properties and 804 MBOE of PUDs were downgraded from Diamondback-operated properties, with the Diamondback-operated downgrades due to changes in the development plan and optimization of the inventory. The purchase of reserves in place of 689 MBOE were due to multiple acquisitions of certain mineral and royalty interests.

During the year ended December 31, 2019, the Partnership's extensions and discoveries of 17,091 MBOE resulted primarily from the drilling of 829 new wells and from 97 new proved undeveloped locations added. The Partnership's negative revisions of previous estimated quantities of 5,337 MBOE were primarily due to proved undeveloped reserves downgrades and realized prices, which were partially offset by extensions and performance. The purchase of reserves in place of 21,914 MBOE were due to multiple acquisitions, primarily the Drop-Down transaction from Diamondback and the acquisition of certain mineral and royalty interests from Santa Elena Minerals, LP.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows are based on the unweighted average, first-day-of-the-month price. 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 Partnership. 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 Partnership's proved oil and natural gas reserves as of December 31, 2021, 2020 and 2019:

	December 31,		
	2021	2020	2019
	(In thousands)		
Future cash inflows	$ 5,763,433	$ 2,460,052	$ 3,218,257
Future production taxes	(416,761)	(181,067)	(237,181)
Future income tax expense	(572,991)	(22,993)	(150,373)
Future net cash flows	4,773,681	2,255,992	2,830,703
10% discount to reflect timing of cash flows	(2,680,564)	(1,232,398)	(1,512,315)
Standardized measure of discounted future net cash flows	$ 2,093,117	$ 1,023,594	$ 1,318,388

The following table presents the weighted average first-day-of–the-month prices for oil, natural gas and natural gas liquids utilized in the computation of future cash inflows:

	December 31,		
	2021	2020	2019
Oil (per Bbl)	$ 64.87	$ 37.61	$ 52.86
Natural gas (per Mcf)	$ 2.97	$ 0.34	$ 0.51
Natural gas liquids (per Bbl)	$ 25.93	$ 11.65	$ 15.79

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

	December 31,		
	2021	2020	2019
	(In thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 1,023,594	$ 1,318,388	$ 1,139,382
Purchase of minerals in place	170,205	10,781	339,814
Divestiture of reserves	(4,402)	(3,481)	—
Sales of oil and natural gas, net of production costs	(468,976)	(227,137)	(274,735)
Extensions and discoveries	615,762	280,486	330,097
Net changes in prices and production costs	863,458	(465,582)	(301,182)
Revisions of previous quantity estimates	45,788	(87,614)	(114,409)
Net changes in income taxes	(243,186)	59,754	56,502
Accretion of discount	103,446	138,901	126,650
Net changes in timing of production and other	(12,572)	(902)	16,269
Standardized measure of discounted future net cash flows at the end of the period	$ 2,093,117	$ 1,023,594	$ 1,318,388

Exhibit 21.1

Viper Energy Partners LP
Subsidiaries of Registrant

Name of Subsidiary	**Jurisdiction of Incorporation**
Viper Energy Partners LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 24, 2022, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Viper Energy Partners LP on Form 10-K for the year ended December 31, 2021. We consent to the incorporation by reference of said reports in the Registration Statements of Viper Energy Partners LP on Form S-3 ASR (File No. 333-260335, effective October 18, 2021) and Form S-8 (File No. 333-196971, effective June 23, 2014).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 24, 2022

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 5, 2022 on estimates of proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP (“Viper”), a subsidiary of Diamondback Energy, Inc., as of December 31, 2021. As independent oil and gas consultants, we hereby consent to the inclusion of our report and the information contained therein and information from our prior reserve reports referenced in this Annual Report on Form 10-K of Viper (this “Annual Report”) and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Viper on Form S-3 ASR (File No. 333-260335, effective October 18, 2021) and Form S-8 (File No. 333-196971, effective June 23, 2014).

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas

February 24, 2022

EXHIBIT 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

1. I have reviewed this Annual Report on Form 10-K of Viper Energy Partners LP (the “registrant”).
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 24, 2022

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer
Viper Energy Partners GP LLC
(as general partner of Viper Energy Partners LP)

EXHIBIT 31.2

CERTIFICATION

I, Teresa L. Dick, certify that:

1. I have reviewed this Annual Report on Form 10-K of Viper Energy Partners LP (the "registrant").

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 24, 2022

/s/ Teresa L. Dick
Teresa L. Dick
Chief Financial Officer
Viper Energy Partners GP LLC
(as general partner of Viper Energy Partners LP)

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

In connection with the Annual Report on Form 10-K of Viper Energy Partners LP (the “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, Travis D. Stice, Chief Executive Officer of Viper Energy Partners GP LLC, the general partner of Viper Energy Partners LP, and Teresa L. Dick, Chief Financial Officer of Viper Energy Partners GP LLC, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to their knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date:	February 24, 2022	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer Viper Energy Partners GP LLC (as general partner of Viper Energy Partners LP)
Date:	February 24, 2022	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer Viper Energy Partners GP LLC (as general partner of Viper Energy Partners LP)

Exhibit 99.1

VIPER ENERGY PARTNERS, LP

Estimated

Future Reserves and Income

Attributable to Certain

Royalty Interests

SEC Parameters

As of

December 31, 2021

/s/ Val Rick Robinson	/s/ Syed R. Rizvi
Val Rick Robinson, P.E.	Syed R. Rizvi
TBPELS License No. 105137	Senior Petroleum Engineer
Managing Senior Vice President	

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 5, 2022

Viper Energy Partners, LP
500 West Texas, Suite 1210
Midland, Texas 79701

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain royalty interests of Viper Energy Partners, LP (Viper), a subsidiary of Diamondback Energy, Inc. (Diamondback) as of December 31, 2021. The subject properties are located in the states of New Mexico and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 31, 2021 and presented herein, was prepared for public disclosure by Viper in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Viper as of December 31, 2021.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
Viper Energy Partners, LP

As of December 31, 2021

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate – Mbbl	49,280	19,960	69,240
Plant Products – Mbbl	19,476	8,557	28,033
Gas – MMcf	134,485	49,205	183,690
MBOE	91,170	36,718	127,888
Income Data ($M)			
Future Gross Revenue	$3,878,633	$1,580,866	$5,459,499
Deductions	79,787	33,040	112,827
Future Net Income (FNI)	$3,798,846	$1,547,826	$5,346,672
Discounted FNI @ 10%	$1,648,450	$698,720	$2,347,170

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Viper. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. Because the interests evaluated herein are royalty interests, the deductions include only ad valorem taxes. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 91 percent and gas reserves account for the remaining 9 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2021 Total Proved
5	$3,206,727
15	$1,883,607
20	$1,589,545
30	$1,231,967

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Viper's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Diamondback's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Viper owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through December, 2021 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Diamondback or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves were estimated by analogy, or a combination of methods. These methods were 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 reserves estimates was considered to be inappropriate.

All proved undeveloped reserves included herein were estimated by the analogy method.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Diamondback has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Diamondback with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamondback. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were based on analog well performance and type-curves where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamondback. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Diamondback furnished us with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Diamondback. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$66.56/bbl	$64.87/bbl
	NGLs	WTI Cushing	$66.56/bbl	$25.93/bbl
	Gas	Henry Hub	$3.598/MMBTU	$2.97/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

As a holder of royalty interests only, Viper bears none of the operating or development costs associated with the underlying properties of this report. Nevertheless, the proved undeveloped reserves in this report have been incorporated herein in accordance with Diamondback’s plans to develop these reserves as of December 31, 2021. The implementation of Diamondback’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Diamondback’s management. As the result of our inquiries during the course of preparing this report, Diamondback has informed us that the development activities included herein have been subjected to and received the internal approvals required by Diamondback’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Diamondback. Diamondback has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Diamondback has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Viper. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Viper.

Viper makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Viper has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Viper, of the references to our name, as well as to the references to our third party report for Viper, which appears in the December 31, 2021 annual report on Form 10-K of Viper. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Viper.

We have provided Viper with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Viper and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Val Rick Robinson

Val Rick Robinson, P.E.
TBPELS License No. 105137
Managing Senior Vice President

[SEAL]

/s/ Syed R. Rizvi

Syed R. Rizvi
Senior Petroleum Engineer

VRR-SRR (LPC)/pl

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2021 continuing education hours, Mr. Robinson attended 30 hours of formalized training including the 2021 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 18 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.