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, 2019
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)

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 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 $1.9 billion on June 28, 2019, 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 7, 2020, 67,805,707 common units representing limited partner interests and 90,709,946 Class B units representing limited partner units were outstanding.

Documents Incorporated By Reference: None

VIPER ENERGY PARTNERS LP

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2019

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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"):

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	Barrels 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.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Deterministic method	The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.
Developed acreage	Acreage allocated or assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Development well	A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole 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	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	Million British Thermal Units.

MMcf	Million cubic feet of natural gas.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD	Proved undeveloped.
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 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 or operations.
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.
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:

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.
Inception	September 18, 2013, the date Viper Energy Partners LLC was formed.
IPO	The partnership's initial public offering of common units.
LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Operating Company	Viper Energy Partners LLC, a Delaware limited liability company and a consolidated subsidiary of Viper Energy Partners LP.
OSHA	Federal Occupational Safety and Health Act.
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.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report, including those detailed under "Item 1A. Risk Factors" in this Annual Report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- the impact of reduced drilling activity;
- regional supply and demand factors, delays or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete and integrate acquisitions of properties or businesses, including the recently completed acquisitions from Diamondback and Santa Elena Minerals, LP.;
- conditions in the capital markets and our ability to obtain capital on favorable terms or at all;
- general economic, business or industry conditions;
- competition in the oil and natural gas industry;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- uncertainties with respect to identified drilling locations and estimates of reserves;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services or personnel;
- restrictions on the use of water;
- the availability of transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- title defects in the properties in which we invest;
- future operating results;
- exploration and development drilling prospects, inventories, projects and programs;

- operating hazards faced by our operators; and

- the ability of our operators to keep pace with technological advancements.

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 securities laws. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to 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 contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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 on February 27, 2014 to, among other things, own, acquire and exploit oil and natural gas properties in North America. We are currently focused on oil and natural gas properties in the Permian Basin and the Eagle Ford Shale. Prior to May 10, 2018, we were treated as a pass-through entity for federal income tax purposes. On May 10, 2018, we elected to be treated as a corporation for U.S. federal income tax purposes, which we refer to as the Tax Election.

Our primary business objective is to provide an attractive return to our unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral, royalty, overriding royalty, net profits and similar interests from Diamondback and from third parties. 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. Diamondback contributed these assets to us upon the closing of our IPO on June 23, 2014.

Like Diamondback, 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 85,000 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.

Our Properties

As of December 31, 2019, our assets consisted of mineral interests underlying 814,224 gross acres and 24,304 net royalty acres in the Permian Basin and Eagle Ford Shale. Diamondback is the operator of approximately 50% of this acreage. As of December 31, 2019, there were 2,026 vertical wells and 3,781 horizontal wells producing on this acreage. Net production during the fourth quarter of 2019 was approximately 26,137 net BOE/d and net production for the year ended December 31, 2019 averaged 21,529 BOE/d. For the years ended December 31, 2019, 2018 and 2017, royalty revenue generated from these mineral interests was $293.8 million, $282.7 million and $160.2 million, respectively.

The estimated proved oil and natural gas reserves of our assets, as of December 31, 2019, were 88,946 MBOE based on a reserve report prepared by Ryder Scott, our independent reserve engineers. Of these reserves, approximately 78% were classified as proved developed producing reserves. Proved undeveloped, or PUD, reserves included in this estimate were from 228 gross horizontal well locations. As of December 31, 2019, our proved reserves were approximately 61% oil, 21% natural gas liquids and 18% natural gas.

As of December 31, 2019, our mineral interests entitle us to receive an average 3% royalty interest on all production from our approximately 814,224 gross acres with no additional future capital or operating expense required. The actual royalty percentage varies by lease and ranges from less than 1% to 25%. The average royalty percentage on a production basis can therefore vary over time depending on the relative amount of production from the various leases.

As of December 31, 2019, based on Diamondback's evaluation of applicable geologic and engineering data with respect to the approximate 50% of our mineral interests for which it is the operator, Diamondback had identified approximately 5,348 potential economic horizontal drilling locations in multiple horizons on the acreage Diamondback operates in the Midland and Delaware Basins at an assumed price of $60.00 per Bbl WTI. We do not have potential (not involving proved reserves) drilling location information with respect to the portion of our properties not operated by Diamondback, although we believe that the portion of the Spanish Trail area in Midland County, Texas operated by others has very similar production characteristics to the portion operated by Diamondback.

Our Relationship with Diamondback

As of December 31, 2019, 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 58% 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 growth 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, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral interests from Diamondback and from third parties. 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 and the Eagle Ford Shale in Texas. We expect the production from our mineral interests will increase as Diamondback and our other operators continue to drill 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. Diamondback was formed, in part, to acquire and develop oil and natural gas properties, some of which will likely meet our acquisition criteria. In addition, Diamondback's executives have an established track record of evaluating, pursuing and consummating oil and natural gas property acquisitions in North America. 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. We may have additional opportunities to work jointly with Diamondback to pursue certain acquisitions of mineral or other interests in oil and natural gas properties from third parties. For example, we and Diamondback may jointly pursue an acquisition where we would acquire mineral or other interests in properties and Diamondback would acquire the remaining working and revenue interests in such properties. We believe this arrangement may give us access to third-party acquisition opportunities that we would not otherwise be in a position to pursue.

- ***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.

- ***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.

Competitive Strengths

We believe that 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, 2019, 373 horizontal drilling rigs were operating in the Permian Basin, representing 53% 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, 2019 was approximately 65% oil, 19% natural gas liquids and 16% natural gas. As of December 31, 2019, our estimated net proved reserves were comprised of approximately 61% oil, 21% natural gas liquids and 18% natural gas.

- ***Multi-year drilling inventory in one of North America's leading oil resource plays.*** We expect our reserves and cash flow to grow organically as our operators continue to drill new wells on our acreage. Diamondback, as the operator of approximately 50% of our acreage as of December 31, 2019, has advised us that it has identified a multi-year inventory of potential drilling locations for our oil-weighted reserves from the acreage underlying our mineral interests. At an assumed price of $60.00 per Bbl WTI, Diamondback had identified approximately 5,348 potential economic horizontal locations on the acreage Diamondback operates in the Midland and Delaware Basins, based on Diamondback's evaluation of applicable geologic and engineering data.

- ***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 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 an average of over 25 years of 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, 2019, 2018 and 2017 were prepared by Ryder Scott. Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder

Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas, 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, 2019 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 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 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. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 85% 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 15% 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.

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. The Executive Vice President–Reservoir Engineering of our general partner is primarily responsible for overseeing the preparation of all of our reserve estimates. The Executive Vice President–Reservoir Engineering of our general partner is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 20 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are 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 data is based on actual production as reported by our operators;
- preparation of reserve estimates by the Executive Vice President–Reservoir Engineering of our general partner or under his direct supervision;
- review by the Executive Vice President–Reservoir Engineering of our general partner 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–Reservoir Engineering of our general partner to the Chief Executive Officer 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, 2019, 2018 and 2017 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,		
	2019	**2018**	**2017**
Estimated proved developed reserves:			
Oil (MBbls)	40,857	29,526	18,788
Natural gas (MMcf)	80,737	49,681	29,256
Natural gas liquids (MBbls)	14,994	7,965	4,536
Total (MBOE)	69,307	45,771	28,200
Estimated proved undeveloped reserves:			
Oil (MBbls)	13,563	12,352	7,097
Natural gas (MMcf)	15,037	11,916	7,139
Natural gas liquids (MBbls)	3,570	3,027	1,759
Total (MBOE)	19,639	17,365	10,046
Estimated Net Proved Reserves:			
Oil (MBbls)	54,420	41,878	25,885
Natural gas (MMcf)	95,774	61,597	36,395
Natural gas liquids (MBbls)	18,564	10,992	6,295
Total (MBOE)(1)	88,946	63,136	38,246
Percent proved developed	78%	72%	74%

(1) Estimates of reserves as of December 31, 2019, 2018 and 2017 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2019, 2018 and 2017, respectively, in accordance with SEC guidelines applicable to reserve estimates as of the end of such periods. 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.

As of December 31, 2019, our proved developed reserves totaled 40,857 MBbls of oil, 80,737 MMcf of natural gas and 14,994 MBbls of natural gas liquids, for a total of 69,307 MBOE. Producing reserves were from 2,026 vertical wells and 3,781 horizontal wells, of which Diamondback was the operator of 472 vertical wells and 993 horizontal wells. The remaining 1,554 vertical wells and 2,788 horizontal wells were operated by various other companies.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See "Item 1A. Risk Factors." We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Proved Undeveloped Reserves

As of December 31, 2019, our PUD reserves totaled 13,563 MBbls of oil, 15,037 MMcf of natural gas and 3,570 MBbls of natural gas liquids, for a total of 19,639 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Our PUD reserves were from 228 horizontal wells, of which Diamondback is the operator of 206 horizontal wells and Concho Resources Inc. operates most of the remaining wells. Of the horizontal locations, 46 are Wolfcamp B wells, 53 are Lower Spraberry wells, 20 are Middle Spraberry/Jo Mill wells, two are Bone Spring wells, one is a Wolfcamp D well, and 106 are Wolfcamp A wells.

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, 2019, none of our total proved reserves were classified as proved developed non-producing.

Changes in PUDs that occurred during 2019 were primarily due to:

- additions of 7,591 MBOE, primarily from 97 horizontal well locations attributable to extensions resulting from strategic drilling of wells to delineate our acreage position;
- downgrade of PUDs into probable category of 3,153 MBOE for 24 short lateral horizontal wells that are not expected to be drilled due to changes in the development plan and optimization of the inventory;
- the conversion of approximately 5,618 MBOE attributable to PUDs into proved developed reserves;
- acquisitions of approximately 3,347 MBOE; and
- positive revisions of approximately 107 MBOE in PUDs primarily due to changes in type curves and realized prices.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

We operate in one reportable segment engaged in the acquisition of oil and natural gas properties. For a description of our revenues, average sales prices and unit costs, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The following table sets forth information regarding the operators’ net production of oil, natural gas and natural gas liquids, all of which is from the Permian Basin and the Eagle Ford Shale in Texas, and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2019	**2018**	**2017**
Production Data:			
Oil (MBbls)	5,123	4,399	2,899
Natural gas (MMcf)	7,657	5,840	3,549
Natural gas liquids (MBbl)	1,459	933	533
Combined volumes (MBOE)	7,858	6,305	4,024
Daily combined volumes (BOE/d)	21,529	17,275	11,023
Average Prices:			
Oil (per Bbl)	$ 51.61	$ 56.13	$ 48.36
Natural gas (per Mcf)	$ 1.06	$ 2.22	$ 2.62
Natural gas liquids (per Bbl)	$ 14.63	$ 24.41	$ 20.02
Combined (per BOE)	$ 37.39	$ 44.83	$ 39.81

Productive Wells

As of December 31, 2019, our operators owned a working interest in 5,807 productive wells located on the acreage in which we have a mineral interest. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Acreage

The following table sets forth information as ofDecember 31, 2019 relating to the gross and net royalty acreage of our mineral interests:

Basin	Gross Acreage	Net Royalty Acreage
Delaware	321,308	11,380
Midland	372,563	12,243
Eagle Ford Shale	120,353	681
Total acreage	814,224	24,304

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 approximately 18% of the net royalty acreage consists of over-riding royalty interests which may be subject to expiration. Net royalty acres are defined as gross acreage multiplied by the average royalty interest.

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. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonal Nature of Business

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

Regulation

The following disclosure describes regulation more directly associated with operators of oil and natural gas properties, including our current operators, and other owners of working interests in oil and natural gas properties. To the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties, we would be directly subject to the same regulations described below. For purposes of this section, where applicable, references to "we," "us," and "our" refer to Viper Energy 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, 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 Resource Conservation and Recovery Act, 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 Resource Conservation and Recovery Act, 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 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 gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. Any such changes in the 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,” the Safe Drinking Water Act, the Oil Pollution Act 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 Clean Water Act 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. 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 Clean Water Act. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 rules. The 2015 rule and the 2019 repeal are subject to several ongoing legal challenges. Also, on January 23, 2020, the EPA and the Corps released a final rule replacing the 2015 rule, and significantly reducing the waters subject to federal regulation under the Clean Water Act. The rule is anticipated to generate further legal challenges. Further, on April 23, 2019, the EPA published an interpretive statement and request for comment, clarifying that the Clean Water Act’s permitting program for pollutant discharges does not apply to releases of pollutants to groundwater. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act’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 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 Oil Pollution Act is the primary federal law for oil spill liability. The Oil Pollution Act 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 Oil Pollution Act 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 Clean Water Act or the Oil Pollution Act may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions

The federal Clean Air Act, 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 Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations 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 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 Clean Air Act 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.

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. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. On November 4, 2019, the Trump Administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement, or what terms would be included in such an agreement. In response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

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 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, there has been public discussion that 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 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 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 Clean Air Act 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, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. Also, on October 15, 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites. In addition, on August 28, 2019, the EPA proposed amendments to 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. Legal challenges are anticipated and thus substantial uncertainty exists regarding the scope of these New Source Performance standards for oil and natural gas operations. The 2012 and 2016 New Source Performance 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 gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. The Texas Railroad Commission adopted rules and regulations implementing this legislation that apply to all wells for which the Texas Railroad Commission issues an initial drilling permit after February 1, 2012. The law requires that the well operator disclose the list of chemical ingredients subject to the requirements of OSHA for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Also, in May 2013, the Texas Railroad Commission adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The rules took effect in January 2014. Additionally, on October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

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 attendant 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, 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 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, 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 employees 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" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Risks Related to Our Business

We may not have sufficient available cash to pay any quarterly distribution on our common units.

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 upon the amount of royalty revenues 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.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods in which we record net losses for financial accounting purposes and may be unable to make cash distributions during periods in which we record net income.

The amount of our quarterly cash distributions, if any, may vary significantly both quarterly and annually and is directly dependent on the performance of our business. We do not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time and could make no distribution with respect to any particular quarter.

Our future business performance may be volatile, and our cash flows may be unstable. We do not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our unitholders will vary significantly from quarter to quarter and may be zero.

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to make any distributions at all.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we distribute an amount equal to the available cash we generate each quarter to our unitholders. However, the board of directors of our general partner may change such policy at any time at its discretion and could elect not to pay distributions for one or more quarters.

In addition, our partnership agreement does not require us to pay any distributions at all. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the board of directors of our general partner, whose interests may differ from those of our common unitholders. Our general partner has limited duties to our unitholders, which may permit it to favor its own interests or the interests of Diamondback to the detriment of our common unitholders.

The volatility of oil and natural gas prices, and particularly the ongoing decline in those prices, due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

Our revenues, operating results, cash available for distribution and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past five years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as WTI Futures Contract 1 price for crude oil has ranged from a low of $26.21 per barrel, or Bbl, in February 2016 to a high of $76.41 per Bbl in October 2018. The Natural Gas Futures Contract 1 price spot market price of natural gas has ranged from a low of $1.64 per MMBtu in March 2016 to a high of $4.84 per MMBtu in November 2018. During 2019, WTI Futures Contract 1 prices ranged from $46.54 to $66.30 per Bbl and the Natural Gas Futures Contract 1 spot market price of natural gas ranged from$2.07 to $3.59 per MMBtu. On January 31, 2020, the WTI Futures Contract 1 posted price for crude oil was $51.56 per Bbl and the Natural Gas Futures Contract 1 spot market price of natural gas was $1.84 per MMBtu. In response to recent volatility in commodity prices, many producers have reduced their capital expenditure budgets. If the prices of oil and natural gas decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. 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.

In addition, lower oil and natural gas prices may also reduce the amount of oil and natural gas that can be produced economically by our operators. This may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if production estimates change or exploration or development results deteriorate, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, they may abandon any well if they reasonably believe that the well can no longer produce oil or natural gas in commercially paying quantities.

If we do not enter into hedging arrangements with respect to the oil and natural gas production from our properties, we will be exposed to the impact of decreases in the price of oil and natural gas. If we do enter into such hedging arrangements, we will expose ourselves to credit risk.

Historically, we have not entered into hedging arrangements to establish, in advance, a price for the sale of the oil and natural gas produced from our properties, but we expect to enter into such arrangements in the future. Without such hedging arrangements, we may realize the benefit of any short-term increase in the price of oil and natural gas, but we will not be protected against decreases in price, and if the price of oil and natural gas continues at current levels or decreases further, our business, results of operations and cash available for distribution may be materially adversely affected. If we do enter into such hedging arrangements with respect to oil and natural gas production from our properties, we will expose ourselves to credit risk, which is the failure of the counterparty to perform under the terms of the arrangement.

We depend on two operators for a substantial portion of the development and production on the properties underlying our mineral interests. Substantially all of our revenue is derived from royalty payments made by these operators. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of either operator to adequately and efficiently develop and operate our acreage could have an adverse effect on our expected growth and our results of operations.

Substantially all of our assets are mineral interests from which we derive royalty income. For theyear ended December 31, 2019, we received approximately 57% and 16% of our royalty revenue from Diamondback and Concho Resources, Inc., respectively. The failure of Diamondback or Concho Resources, Inc. 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 of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- 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 than we currently anticipate.

Approximately 22% of our total estimated proved reserves as of December 31, 2019 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. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or further decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

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. 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, 2019, 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 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.

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.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

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. During the year ended December 31, 2019, Diamondback, which is the operator for approximately 50% of the acreage associated with our properties, drilled a total of 184 gross wells, of which 56 wells were in various stages of completion. If the wells in the process of being completed 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 plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $9.95, $9.33 and $10.07 for the years ended December 31, 2019, 2018 and 2017, respectively.

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.

Although we recorded an impairment in 2016 and 2015, no impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2019, 2018 and 2017. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations–Critical Accounting Policies and Estimates–Method of Accounting for Oil and Natural Gas Properties.” If the prices of oil and natural gas decline, we may be required to 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. Our historical estimates of proved reserves and related valuations as of December 31, 2019, 2018 and 2017, were prepared by Ryder Scott, an independent petroleum engineering firm, which conducted a well-by-well review of all our properties for the period covered by its reserve report using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that we ultimately recover being different from our reserve estimates. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage.

The estimates of reserves as of December 31, 2019, 2018 and 2017 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2019, 2018 and 2017, respectively, in accordance with the SEC guidelines applicable to reserve estimates for such period.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe because they have become uneconomic or otherwise.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, volatility in consumer confidence and job markets, may result in an economic slowdown or recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

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.

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

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 our executive team, 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. Diamondback has employment agreements with these executives and certain other employees of our general partner which contain restrictions on competition with the business or operations of Diamondback and its subsidiaries until the later of the termination of their employment with or other affiliation with such entities and for a period of six months thereafter. However, as a practical matter, such employment agreements may not assure the retention of Diamondback's employees. 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.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. 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 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 competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves 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 exploratory prospects and producing oil and natural gas properties.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer based programs. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

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.

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the senior notes and our other indebtedness.

As of December 31, 2019, we had a total long-term debt of $586.8 million, consisting of $500.0 million aggregate principal amount of our outstanding 5.375% Senior Notes due 2027, which we refer to herein as the senior notes, and $96.5 million in outstanding borrowings under the Operating Company's revolving credit facility. As of December 31, 2019, the borrowing base under the Operating Company's revolving credit facility was $775.0 million, and the Operating Company had $678.5 million of available borrowing capacity under its revolving credit facility. We and the Operating Company may in the future incur significant additional indebtedness under our revolving credit facilities or otherwise in order to make acquisitions or for other purposes.

Our level of indebtedness could have important consequences to you and affect our operations in several ways, including the following:

- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to the notes, including any repurchase obligations that may arise thereunder;

- a significant portion of our cash flows could be used to service the senior notes and our other indebtedness, which could reduce the funds available to us for operations and other purposes;

- a high level of debt could increase our vulnerability to general adverse economic and industry conditions;

- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay distributions and make certain investments;

- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;

- our debt covenants may also limit management's discretion in operating our business and our flexibility in planning for, and reacting to, changes in the economy and in our industry;

- a high level of debt may make it more likely that a reduction in the borrowing base following a periodic redetermination could require us and the Operating Company to repay a portion of the then-outstanding bank borrowings;

- a high level of debt could limit our ability to access the capital markets to raise capital on favorable terms;

- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and

- we may be vulnerable to interest rate increases, as the borrowings under the Operating Company's revolving credit facility are at variable interest rates.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our common units or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

Restrictive covenants in the Operating Company's revolving credit facility, the indenture governing the senior 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 our outstanding senior notes 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 senior 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.

Under the Operating Company's revolving credit facility, the Operating Company may, among other things, designate one or more of its subsidiaries as "unrestricted subsidiaries" that are not guarantors and are not subject to certain restrictions contained in the revolving credit facility. As of the date of this offering circular, the Operating Company does not have any unrestricted subsidiaries, but may in the future designate one or more of its subsidiaries as an unrestricted subsidiary under its revolving credit facility.

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 will govern the notes offered hereby. 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 senior 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.

As of December 31, 2019, the maximum credit amount under the Operating Company's revolving credit facility was set at $2.0 billion and the borrowing base (based on our oil and natural gas reserves and other factors) was set at $775.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. 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 our outstanding senior notes 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.

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

We, the Operating Company and any future subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of the Operating Company's revolving credit facility and the indenture governing our outstanding senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2019, we had $586.8 million of total indebtedness (consisting of $500.0 million aggregate principal amount of the senior notes and $96.5 million in outstanding borrowings under the Operating Company's revolving credit facility), the borrowing base under the revolving credit facility was $775.0 million, and the Operating Company had $678.5 million of available borrowing capacity under its revolving credit facility. In addition, the indenture governing the senior notes and the revolving credit facility allow us to issue additional notes under certain circumstances which will also be guaranteed by the guarantor. The indenture governing the senior notes allow us to incur certain other additional secured debt and allow us to have subsidiaries that do not guarantee the senior notes and which may incur additional debt. In addition, the indenture governing the senior notes does not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiary now face could intensify.

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

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

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

Our earnings are exposed to interest rate risk associated with borrowings under the Operating Company's revolving credit facility. The terms of the Operating Company's revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (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 0.75% to 1.75% per annum in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of the loans outstanding in relation to the borrowing base. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve 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. As of December 31, 2019, there was $96.5 million in borrowings outstanding under the revolving credit facility, with a weighted average interest rate of 4.30%. 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) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United States or elsewhere.

Risks Related to Operators and Other Working Interest Owners

The operators of our properties are subject to the risks and uncertainties described below, and, as the owner of mineral interests, we are indirectly exposed to the same risks and uncertainties. The following also describes risks that may affect our business and operations to the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties. 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.

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

The oil and natural gas industry is capital intensive. Our operators may not have capital resources to maintain planned or future levels of capital expenditures. Further, our operators' actual capital expenditures could exceed their capital expenditure budget. In the event our operators' capital expenditure requirements at any time are greater than the amount of capital they have available, they could be required to seek additional sources of capital.

If our operators are unable to fund their capital requirements, they may be required to curtail operations relating to the exploration and development of our properties, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

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.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our 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.

The potential drilling locations identified by the operators of our properties are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

The ability of the operators of our properties to drill and develop identified potential drilling locations will depend on a number of uncertainties, including the availability of capital, construction of infrastructure, regulatory changes and approvals, costs, drilling results, the availability of water and weather conditions. Further, identified potential drilling locations are typically in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. The operators will not be able to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable or whether wells drilled on different spacing assumptions will produce at materially different rates. The use of technologies and the study of producing fields in the same area will not enable the operators of our properties to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, the operators of our properties may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If the operators of our properties drill wells that we identify as dry holes in current and future drilling locations, their drilling success rate may decline and materially harm our business.

We will not be able to assure our unitholders that the analogies our operators draw from available data from wells drilled, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by our operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations our operators have identified will ever be drilled or if they will be able to produce oil or natural gas from these or any other potential drilling locations. As such, the actual drilling activities of the operators of our properties may materially differ from those identified, which could adversely affect our business.

Acreage must be drilled before lease expiration, generally within three to five years, to hold the acreage by production. Our operators' failure to drill sufficient wells to hold acreage may result in a loss of the lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. Any reduction in our operators' drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations, which may terminate our overriding royalty interests derived from such leases. If our royalties are derived from mineral interests and production or drilling ceases on the leased properties, the lease is typically terminated, subject to certain exceptions, and such mineral rights revert back to us and we will have to seek new lessees to explore and develop such mineral interests. Any such losses of our operators or lessees could materially and adversely affect the timing and/or growth of our financial condition and cash available for distribution.

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

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

Restrictions on the ability of our operators to obtain water may have an adverse effect on our cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Parts of Texas have experienced drought conditions in the past years. As a result, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If our operators are unable to obtain water to use in their operations from local sources, or they are unable to effectively utilize flowback water, our operators may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our cash flows and, as a result, may have an adverse effect on our financial condition, results of operations and cash available for distribution.

The results of our exploratory drilling in shale plays will be subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

The operators of our properties may use the latest drilling and completion techniques. Risks that our operators may face while drilling include, but are not limited to, landing their well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that our operators may face while completing wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent our operators engage in horizontal drilling, those activities may adversely affect our operators' ability to successfully drill in identified vertical drilling locations. Furthermore, certain of the new techniques our operators may adopt, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently the operators of our properties may be less able to predict future drilling results in these areas.

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

The marketability of oil and natural gas production is dependent upon transportation and other facilities, certain of which neither we nor the operators of our properties control. If these facilities are unavailable, our operators' operations could be interrupted and our financial results and cash available for distribution could be adversely affected.

The marketability of our operators' oil and natural gas production will depend in part upon the availability, proximity and capacity of transportation facilities, including gathering systems, trucks and pipelines, certain of which are owned by third parties. Neither we nor the operators of our properties control these third party transportation facilities and our operators' access to them may be limited or denied. Insufficient production from the wells to support the construction of pipeline facilities by their purchasers or a significant disruption in the availability of our operators' or third party transportation facilities or other production facilities could adversely impact their ability to deliver to market or produce oil and natural gas and thereby cause a significant interruption in our operators' operations. For example, on certain occasions, our operators have experienced high line pressure at their tank batteries with occasional flaring due to the inability of the gas gathering systems to support the increased production of natural gas in the Permian Basin. If our operators are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, they may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our operators' or our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in some cases, our operators are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced on our properties, could adversely affect our financial condition, results of operations and cash available for distribution.

Oil and natural gas operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive and could result in significant liabilities.

Operations on properties in which we hold interests are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all operations. Moreover, these laws and regulations impose strict requirements for water and air pollution control and solid waste management.

Laws and regulations governing exploration and production may also affect production levels. Our operators are required to comply with federal and state laws and regulations governing conservation matters, including: provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; the plugging and abandonment of wells; and the removal of related production equipment. Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increase capital costs on the part of operators and third party downstream natural gas transporters.

Our operators are also required to comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Significant expenditures may be required to comply with the governmental laws and regulations described above. Even if federal regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term, and at the state and local levels. See "Items 1 and 2. Business and Properties-Regulation" for a description of the laws and regulations that affect our operators and that, to the extent we acquire working interests in the future, will affect us. These and other potential regulations could increase the operators' operating costs, reduce liquidity, delay operations or otherwise alter the way the operators conduct their business, any of which could have a material adverse effect on the amount of cash available for distribution to our unitholders.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs to our operators and additional operating restrictions or delays.

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 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 Clean Air Act 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 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. For or a more detailed discussion of federal laws concerning hydraulic fracturing, see “Items 1 and 2. Business and Properties–Regulation–Regulation of Hydraulic Fracturing.”

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 the operators of our properties 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. For a more detailed discussion of state and local laws and initiatives concerning hydraulic fracturing, see “Items 1 and 2. Business and Properties–Regulation–Regulation of Hydraulic Fracturing.”

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 the operators of our properties 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 attendant permitting delays and potential increases in costs. Such changes could cause the operators of our properties to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our or our operators' businesses of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Oil and natural gas operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our operators' business activities.

The operators of our properties may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to their exploration, development and production activities. These laws and regulations may, among other things: (i) require the operators of our properties to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations by our operators result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, our operators may be required to remediate contaminated properties operated by them or facilities of third parties that received waste generated by their operations regardless of whether such contamination resulted from the conduct of others or from consequences of their own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operators' operations. In addition, the risk of accidental and/or unpermitted spills or releases from their operations could expose them to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements applicable to the operators of our properties, our business and cash available for distribution could be materially adversely affected.

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

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

The regulation of greenhouse gas emissions could result in increased operating costs and reduced demand for the oil and natural gas produced on our properties.

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. While our operators are subject to certain federal greenhouse gas monitoring and reporting requirements, their operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed greenhouse gas rules and regulations, see "Items 1 and 2. Business and Properties–Regulation–Environmental Regulation-Climate Change."

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. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. On November 4, 2019, the Trump Administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement, or what terms would be included in such an agreement. In response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of their products and reserves. As the operations on our properties also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our operators’ 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 or our operators’ 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 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. An unfavorable ruling in any such case could significantly impact our operators’ operations on our properties, which could have an adverse impact on our financial condition and cash flows.

Moreover, there has been public discussion that 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 can interfere with production on our properties and increase our operators’ 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 operations on our properties.

Legislation or regulatory initiatives intended to address seismic activity could restrict drilling and production activities of our operators, as well as their ability to dispose of produced water gathered from such activities.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, 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 or other oil and gas waste 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. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may adversely affect our and our operators' business, financial condition and cash available for distribution.

Our operators' drilling activities are subject to many risks. For example, wells drilled by them may not be productive or they may not be able to recover all or any portion of their investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies used do not provide conclusive knowledge prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond control, and increases in those costs can adversely affect the economics of a project. Further, our or our operators' drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations, including the drilling of development wells, are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and cash available for distribution to our unitholders may be adversely affected.

Operating hazards and uninsured risks may result in substantial losses and could adversely affect our results of operations and cash available for distribution.

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

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

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

We may not have coverage if we are unaware of a sudden and accidental pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We do not have, and do not intend to have, coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure our unitholders that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash available for distribution.

Our mineral acreage is concentrated in an area of high industry activity, which may make it difficult to hire, train or retain qualified personnel needed to manage and operate our assets.

Our mineral acreage is concentrated in the Permian Basin, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future.

Any delay or inability of our operators to secure the personnel necessary to continue or complete development activities on our properties could lead to a reduction in production volumes. Any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our business, financial condition and cash available for distribution.

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

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

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

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

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 for drilling 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 planned growth and cash flows.

A terrorist attack or armed conflict could harm our business.

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

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

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our 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 and any insurance coverage 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 do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of our business.

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.

The board of directors of our general partner has adopted a policy pursuant to which the Operating Company will distribute all of the available cash it generates each quarter and we, in turn, will distribute all of the available cash we receive from the Operating Company to our common unitholders. This policy could limit our ability to grow and make acquisitions.

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. The incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, would reduce the available cash that we have to distribute to our unitholders. Further, following the Tax Election on May 10, 2018, available cash for each quarter will also be reduced for cash needed for income taxes payable by us, if any.

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.

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:

- 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;
- 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
- 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:
  - 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
  - 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. As ofDecember 31, 2019, Diamondback owned approximately 58% of our total units outstanding.

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 (1) 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 (2) 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, 2019, Diamondback owned approximately 58% 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.

As of December 31, 2019, we had 67,805,707 common units and 90,709,946 Class B units outstanding. All of the Class B units are beneficially owned by Diamondback and Class B units must be redeemed (together with an equal number of units of the Operating Company, or the OpCo units) for common units prior to their sale to any person or entity not affiliated with Diamondback. 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.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

We have developed and maintain a system of internal controls for compliance with public reporting requirements. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded partnership. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. For example, Section 404 requires us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

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. If a dispute were to arise between a limited partner and us or our officers, directors or employees, the limited partner may be required to pursue its legal remedies in Delaware which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment. These provisions may have the effect of discouraging lawsuits against us and our general partner's directors and officers.

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 and, prior to May 10, 2018, we were treated as a pass-through entity for federal income tax purposes. On May 10, 2018, we elected to be treated as a corporation for U.S. federal income tax purposes. As a result, we are now subject to tax as a corporation at the corporate tax rate of 21%. While we may not have taxable income in the next three years due to an agreement between Diamondback and us to specially allocate to Diamondback priority allocations of $300 million of the Operating Company's income and gains over losses and deductions (but before depletion), there's 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 will likely 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.

Recently enacted U.S. tax legislation as well as future U.S. tax legislations may adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act, which we refer to as the Tax Act, that significantly reforms the Internal Revenue Code of 1986, as amended, which we refer to as the Code. Among other changes, the Tax Act (i) reduces the maximum U.S. corporate income tax rate from 35% to 21%, (ii) preserves long-standing upstream oil and gas tax provisions such as immediate deduction of intangible drilling, (iii) allows for immediate expensing of capital expenditures for tangible personal property for a period of time, (iv) modifies the provisions related to the limitations on deductions for executive compensation of publicly traded corporations and (v) enacts new limitations regarding the deductibility of interest expense. The Tax Act is complex and far-reaching, and while we have evaluated the resulting impact of its enactment on us and recorded adjustments as required in our financial statements, aspects of the Tax Act are unclear and may not be clarified for some time. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations and assumptions could have an adverse effect on our business, results of operations, financial condition and cash flow.

In addition, 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 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. While these specific changes are not included in the Tax Act, 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 flows.

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.

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 four holders of record of our common units on February 7, 2020.

Cash Distribution Policy

The board of directors of our general partner has adopted a policy pursuant to which the Operating Company distributes all of the available cash it generates in each quarter to its unitholders (including us), and pursuant to which 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. We expect that the Operating Company's available cash for each quarter will generally equal its Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations and 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, and that our available cash for each quarter will generally equal our Adjusted EBITDA (which is our proportional share of the available cash of the Operating Company for the quarter), less, as a result of the Tax Election, cash needed and 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.

Recent Sales of Unregistered Securities

As previously reported, on October 1, 2019, we issued approximately 18.3 million new Class B units and the Operating Company issued approximately 18.3 million new units, in each case to Diamondback and one of its subsidiaries, as part of the consideration for the drop-down acquisition described elsewhere in this report, which consideration also included $190.2 million in cash after giving effect to closing adjustments for net title benefits.

In addition, as previously reported, on October 31, 2019, we issued to Santa Elena Minerals, LP, or Santa Elena, approximately 5.2 million common units representing limited partner interests in us as consideration for certain assets we acquired from Santa Elena in that acquisition described elsewhere in this report, and the Operating Company issued to us approximately 5.2 million of new units of the Operating Company.

These units were issued in reliance upon the exemption from the registration requirements of the Securities Act, provided by Section 4(a)(2) of the Securities Act as sales by an issuer not involving any public offering.

Repurchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. The following selected financial data should be read in conjunction with "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 Annual Report.

Viper Energy Partners LP was formed in February 2014 and did not own any assets prior to June 17, 2014, the date Viper Energy Partners, LLC, the then-subsidiary of Diamondback, was contributed to Viper Energy Partners LP. This contribution was accounted for as a combination of entities under common control.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2019, 2018 and 2017 and the balance sheet data as of December 31, 2019 and 2018 are derived from our audited consolidated financial statements included elsewhere in this Annual Report. The historical financial data for the years ended December 31, 2016 and 2015 and the balance sheet data as of December 31, 2017, 2016 and 2015 are derived from our previously filed audited financial statements, which are not included in this Annual Report on Form 10-K.

	Year Ended December 31,				
(In thousands, except per unit amounts)	**2019**	**2018**	**2017**	**2016**	**2015**
Statement of Operations Data:					
Total operating income	$ 298,283	$ 288,820	$ 172,033	$ 79,146	$ 74,859
Total costs and expenses	104,743	85,833	58,212	88,457	50,484
Income (loss) from operations	193,540	202,987	113,821	(9,311)	24,375
Total other income (expense), net	(13,912)	(12,475)	(2,343)	(1,588)	44
Income (loss) before income taxes	179,628	190,512	111,478	(10,899)	24,419
Benefit from income taxes	(41,582)	(72,365)	—	—	—
Net income (loss)	221,210	262,877	111,478	(10,899)	24,419
Net income attributable to non-controlling interest	174,929	118,919	—	—	—
Net income (loss) attributable to Viper Energy Partners LP	$ 46,281	$ 143,958	$ 111,478	$ (10,899)	$ 24,419
Net income (loss) attributable to common limited partners per unit:					
Basic	$ 0.75	$ 2.01	$ 1.07	$ (0.13)	$ 0.31
Diluted	$ 0.75	$ 2.01	$ 1.07	$ (0.13)	$ 0.31
Weighted average number of common limited partner units outstanding:					
Basic	61,744	71,546	104,318	83,081	79,717
Diluted	61,787	71,626	104,383	83,081	79,727
Cash dividends declared per common unit	$ 1.76	$ 2.17	$ 1.43	$ 0.80	$ 0.84

(In thousands)	December 31, 2019	2018	2017	2016	2015
Balance Sheet Data:					
Cash and cash equivalents	$ 3,602	$ 22,676	$ 24,197	$ 9,213	$ 539
Total assets	2,785,626	1,654,064	1,013,037	670,549	529,731
Current liabilities	13,432	6,022	5,629	2,151	87
Long-term debt, net	586,774	411,000	93,500	120,500	34,500
Total unitholders' equity	931,135	542,102	913,908	547,898	495,144
Total equity	$ 2,185,420	$ 1,237,042	$ 913,908	$ 547,898	$ 495,144

(In thousands)	Year Ended December 31, 2019	2018	2017	2016	2015
Other Financial Data:					
Net cash provided by operating activities	$ 236,691	$ 244,493	$ 139,219	$ 68,627	$ 63,832
Net cash used in investing activities	$ (530,572)	$ (614,253)	$ (344,079)	$ (205,721)	$ (43,907)
Net cash provided by (used in) financing activities	$ 274,807	$ 368,239	$ 219,844	$ 145,768	$ (34,496)

(In thousands)	Year Ended December 31, 2019	2018	2017	2016	2015
Adjusted EBITDA attributable to Viper Energy Partners LP(1)	$ 124,374	$ 140,888	$ 157,556	$ 72,660	$ 68,317

(1) For more information, please read "—Non-GAAP Financial Measure" below.

Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA in evaluating cash flow that will be available to pay distributions to our common unitholders.

We define Adjusted EBITDA as net income (loss) plus interest expense, net, non-cash unit-based compensation expense, depletion expense, impairment expense, (gain) loss on revaluation of investment and benefit from income taxes. Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss), royalty income, cash flow from operating activities or any other measure of financial performance or liquidity presented as determined in accordance with GAAP. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDA, to net income, our most directly comparable GAAP financial measure for the periods indicated:

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(in thousands)				
Net income (loss)	$ 221,210	$ 262,877	$ 111,478	$ (10,899)	$ 24,419
Interest expense, net	21,076	13,849	3,164	2,455	1,110
Non-cash unit-based compensation expense	1,822	2,763	2,395	3,815	3,929
Depletion	78,178	58,830	40,519	29,820	35,436
Impairment	—	—	—	47,469	3,423
(Gain) loss on revaluation of investment	(4,832)	550	—	—	—
Benefit from income taxes	(41,582)	(72,365)	—	—	—
Consolidated Adjusted EBITDA	275,872	266,504	157,556	72,660	68,317
EBITDA attributable to non-controlling interest	(151,498)	(125,616)	—	—	—
Adjusted EBITDA attributable to Viper Energy Partners LP	$ 124,374	$ 140,888	$ 157,556	$ 72,660	$ 68,317

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 in February 2014 to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin and Eagle Ford Shale. Prior to May 10, 2018, we were treated as a pass-through entity for federal income tax purposes. On May 10, 2018, we elected to be treated as a corporation for U.S. federal income tax purposes. For additional information regarding the tax status and the tax election, please refer to our Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and our Current Report on Form 8-K filed with the SEC on May 15, 2018.

As of December 31, 2019, 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 all of our 90,709,946 outstanding Class B units, representing approximately 58% of our total units outstanding. Diamondback also owns and controls our general partner.

We operate in one reportable segment engaged in the acquisition of oil and natural gas properties. Our assets consist primarily of producing oil and natural gas properties principally located in the Permian Basin of West Texas.

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 2019 and fiscal year 2018. A discussion of changes in our results of operations from fiscal year 2017 to fiscal year 2018 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, 2018, filed with the Securities and Exchange Commission on February 25, 2019, as amended on March 12, 2019, and is incorporated by reference in this report from such prior Annual Report on Form 10-K.

Sources of Our Income

Our income is primarily derived from royalty payments we receive from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. Royalty payments may vary significantly from period to period as a result of changes in commodity prices, production mix and volumes of production sold by our operators.

The following table presents the breakdown of our operating income for the following periods:

	Year Ended December 31,	
	2019	2018
Operating income:		
Royalty income:		
Oil sales	89%	85%
Natural gas sales	3%	4%
Natural gas liquid sales	7%	8%
Lease bonus income	1%	3%
	100%	100%

As a result, our income is more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Our income may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile.

During 2019, WTI Futures Contract 1 price for crude oil ranged from $46.54 to $66.30 per Bbl and the Natural Gas Futures Contract 1 price ranged from $2.07 to $3.59 per MMBtu. On December 31, 2019, the WTI Futures Contract 1 price for crude oil was $61.06 per Bbl and the Natural Gas Futures Contract 1 price was $2.19 per MMBtu. Lower prices may not only decrease our income, but also potentially the amount of oil and natural gas that our operators can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be redetermined at the discretion of our lenders.

2019 Transactions and Recent Developments

Equity Offering

On March 1, 2019, we completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 54% of our total units then outstanding. We received net proceeds from this offering of approximately $340.6 million, after deducting underwriting discounts and commissions and estimated offering expenses. We used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the outstanding borrowings under the Operating Company's revolving credit facility and finance acquisitions during the period.

Drop-Down Acquisition

On October 1, 2019, we completed the acquisition of certain mineral and royalty interests from subsidiaries of Diamondback for approximately 18.3 million of our 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, which we refer to as 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%, which we refer to as the Drop-Down Assets. We 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. In connection with the closing of the Drop-Down Acquisition, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million.

Santa Elena Acquisition

On October 31, 2019, we completed the acquisition of certain mineral and royalty interests from Santa Elena, which we refer to as the Santa Elena Acquisition, which assets were immediately contributed by us 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, which we refer to as the Santa Elena Assets.

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

Other Recent Acquisitions

In addition, during the year ended December 31, 2019, we 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. We funded these acquisitions with cash on hand, a portion of the net proceeds from our first quarter 2019 offering of common units and borrowings under the Operating Company's revolving credit facility.

As a result of the Drop-Down Acquisition, the Santa Elena Acquisition and the other recently completed acquisitions described above, which we collectively refer to as the Recent Acquisitions, as of December 31, 2019, our assets included mineral interests representing 814,224 gross (24,304 net royalty) acres in the Permian Basin and the Eagle Ford Shale, approximately 50% of which are operated by Diamondback.

Notes Offering

On October 16, 2019, we completed an offering, which we refer to as the Notes Offering, of our 5.375% Senior Notes due 2027 in the aggregate principal amount of $500.0 million. We received net proceeds of approximately $490.0 million from the Notes Offering. We loaned the gross proceeds of the Notes Offering to the Operating Company. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility.

Increase in the Borrowing Base under the Operating Company's Revolving Credit Facility

In connection with our fall redetermination in November 2019, the borrowing base under the Operating Company's revolving credit facility was increased from $725.0 million to $775.0 million.

Production and Operational Update

Our average daily production during the year ended December 31, 2019 was 21,529 BOE/d (65% oil), and our operators received an average of $51.61 per Bbl of oil, $14.63 per Bbl of natural gas liquids and $1.06 per Mcf of natural gas, for an average realized price of $37.39 per BOE. The average realized price of $1.06 per Mcf of natural gas was primarily due to the pricing terms under our operators' natural gas delivery contracts, which are generally tied to NYMEX price quoted at Henry Hub. Actual volumetric prices realized from the sale of natural gas, however, differ from the quoted NYMEX price as a result of quality and location differentials. During the fourth quarter, natural gas sold at the WAHA Hub in Pecos County, Texas averaged a differential of $(1.22) relative to the NYMEX price quoted at Henry Hub. Our operators may have varying terms under which they sell their natural gas, but we are mostly impacted by location differences resulting from supply and demand imbalances and limited takeaway capacity within the Permian Basin. We expect to realize approximately 97% to 100% of WTI in 2020.

During the fourth quarter of 2019, we estimate that 123 gross (3.4 net 100% royalty interest) horizontal wells with an average royalty interest of 2.7% were turned to production on our existing acreage position with an average lateral length of 8,895 feet. Of these 123 gross wells, Diamondback is the operator of 41 with an average royalty interest of 5.1%, and the remaining 82 gross wells, which have an average royalty interest of 1.6%, are operated by third parties. Additionally, during the fourth quarter of 2019, we closed nine acquisitions for an aggregate purchase price of approximately $912.9 million, which added a further 738 gross (28.8 net 100% royalty interest) producing horizontal wells with an average royalty interest of 3.9%. In total, as of December 31, 2019, we had 2,452 vertical wells and 4,024 horizontal wells producing on our acreage with a combined average net royalty interest of 3.8%. There continues to be active development on our mineral acreage as represented by approximately 497 gross horizontal wells currently in the process of active development, in which we expect to own an average 2.0% net royalty interest (9.9 net 100% royalty interest). These wells currently in the process of active development include various wells currently being drilled by the 53 active rigs which were on our acreage as of January 15, 2020, in addition to other wells currently waiting to be completed, actively in the process of being completed or waiting to be turned to production. Additionally, based on Diamondback's current completion schedule and third party operators' permits, we believe that a further 420 gross (10.4 net 100% royalty interest) wells with an average royalty interest of 2.5%, for which the process or active development has not yet begun, will be turned to production within the next 12 to 15 months. Based on Diamondback's current completion schedule, we expect to have exposure to approximately 70% of Diamondback's expected completions with an average net revenue interest of greater than 5%, translating to at least 12 Diamondback-operated 100% royalty interest wells turned to production in 2020, as compared to less than eight in 2019. The acquisitions closed during the fourth quarter of 2019 contributed 62 gross (1.4 net 100% royalty interest) horizontal wells in the process of active development out of the total 497 currently in Viper's portfolio. Further, the Recent Acquisitions also contributed 47 gross (2.1 net 100% royalty interest) permits out of the total 420 total gross wells for which the process of active development has not yet begun, but which are expected to be turned to production within the next 12 to 15 months.

We declared a cash dividend for the fourth quarter of 2019 of $0.45 per common unit, payable on February 28, 2020, to unitholders of record at the close of business on February 21, 2020.

Principal Components of Our Cost Structure

Production and Ad Valorem Taxes

Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas interests.

General and Administrative

In connection with the closing of the IPO, our general partner and Diamondback entered into the first amended and restated agreement of limited partnership, dated as of June 23, 2014. The partnership agreement requires us 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.

Depreciation, Depletion and Amortization

Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization.

Income Tax Expense

Prior to our change in federal income tax status, we were organized as a pass-through entity for income tax purposes. As a result, our partners were responsible for federal income taxes on their share of our taxable income. Subsequent to our change in federal income tax status, we are subject to federal income taxes at the corporate statutory rate of 21%.

We are subject to the Texas margin tax. For the year ended December 31, 2019, we did not accrue any Texas margin tax. For the year ended December 31, 2018, we accrued $0.2 million, for Texas margin tax payable pursuant to our tax sharing agreement with Diamondback.

Results of Operations

The following table summarizes our revenue and expenses and production data for the periods indicated:

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Operating Results:		
Operating income:		
Royalty income	$ 293,811	$ 282,661
Lease bonus income	4,117	6,029
Other operating income	355	130
Total operating income	298,283	288,820
Costs and expenses:		
Production and ad valorem taxes	19,076	19,048
Depletion	78,178	58,830
General and administrative expenses	7,489	7,955
Total costs and expenses	104,743	85,833
Income from operations	193,540	202,987
Other income (expense):		
Interest expense, net	(21,076)	(13,849)
Gain (loss) on revaluation of investment	4,832	(550)
Other income, net	2,332	1,924
Total other expense, net	(13,912)	(12,475)
Income before income taxes	179,628	190,512
Benefit from income taxes	(41,582)	(72,365)
Net income	221,210	262,877
Net income attributable to non-controlling interest	174,929	118,919
Net income attributable to Viper Energy Partners LP	$ 46,281	$ 143,958

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Production Data:		
Oil (MBbls)	5,123	4,399
Natural gas (MMcf)	7,657	5,840
Natural gas liquids (MBbls)	1,459	933
Combined volumes (MBOE)	7,858	6,305
Average daily oil volumes (BO/d)	14,035	12,053
Average daily combined volumes (BOE/d)	21,529	17,275
% Oil	65%	70%
Average sales prices:		
Oil, realized ($/Bbl)	$ 51.61	$ 56.13
Natural gas realized ($/Mcf)(1)	$ 1.06	$ 2.22
Natural gas liquids ($/Bbl)	$ 14.63	$ 24.41
Average price realized ($/BOE)	$ 37.39	$ 44.83
Average Costs ($/BOE):		
Production and ad valorem taxes	$ 2.43	$ 3.02
General and administrative - cash component	0.72	0.82
Total operating expense - cash	$ 3.15	$ 3.84
General and administrative - non-cash component	$ 0.23	$ 0.44
Interest expense, net	$ 2.68	$ 2.20
Depletion	$ 9.95	$ 9.33

(1) The average realized price of $1.06 per Mcf of natural gas was primarily due to the pricing terms under our operators' natural gas delivery contracts, which are generally tied to NYMEX price quoted at Henry Hub. Actual volumetric prices realized from the sale of natural gas, however, differ from the quoted NYMEX price as a result of quality and location differentials. During the fourth quarter, natural gas sold at the WAHA Hub in Pecos County, Texas averaged a differential of $(1.22) relative to the NYMEX price quoted at Henry Hub. Our operators may have varying terms under which they sell their natural gas, but we are mostly impacted by location differences resulting from supply and demand imbalances and limited takeaway capacity within the Permian Basin.

Comparison of the Years Ended December 31, 2019 and ***2018***

Royalty Income

Our royalty income for the years ended December 31, 2019 and 2018 was $293.8 million and $282.7 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

The 25% increase in combined volumes sold by our operators during the year ended December 31, 2019 as compared to the year ended December 31, 2018 was partially offset by the decrease in average prices received.

	2019 vs. 2018		
	Change in prices	Production volumes(1)	Total net dollar effect of change
	(dollars in thousands except change in prices)		
Effect of changes in price:			
Oil	$ (4.52)	5,123	$ (23,153)
Natural gas	$ (1.17)	7,657	(8,922)
Natural gas liquids	$ (9.78)	1,459	(14,275)
Total income due to change in price			$ (46,350)

	2019 vs. 2018		
	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change
	(dollars in thousands except average prices)		
Effect of changes in production volumes:			
Oil	723	$ 56.13	$ 40,607
Natural gas	1,817	$ 2.22	4,038
Natural gas liquids	527	$ 24.41	12,855
Total income due to change in production volumes			57,500
Total change in income			$ 11,150

(1) Production volumes are presented in MBbls for oil and natural gas liquids and MMcf for natural gas.

Lease Bonus Income

Lease bonus income decreased by $1.9 million from $6.0 million for the year ended December 31, 2018 to $4.1 million for the year ended December 31, 2019. During the year ended December 31, 2019, we received $0.9 million which was attributable to lease bonus payments to extend the term of 13 leases, and $3.2 million attributable to lease bonus payments on 16 new leases. During the year ended December 31, 2018, we received $3.4 million which was attributable to lease bonus payments to extend the term of 15 leases, and $2.7 million attributable to lease bonus payments on six new leases.

Other Operating Income

Other operating income was $0.4 million and $0.1 million for the years ended December 31, 2019 and 2018, respectively, primarily related to surface damage payments.

Production and Ad Valorem Taxes

Production taxes per unit of production for the years ended December 31, 2019 and 2018 were $1.83 and $2.17, respectively. The decrease in production taxes per unit of production during the year ended December 31, 2019 as compared to 2018 was primarily due to a 25% increase in production volumes, as compared to a smaller increase in revenue year over year. Ad valorem taxes per unit of production for the years ended December 31, 2019 and 2018 were $0.60 and $0.85, respectively. The decrease in ad valorem taxes per production unit during the year ended December 31, 2019 as compared to 2018 was primarily due to a higher percentage increase in production volumes as compared to the increase in the valuation of oil and natural gas interests year over year.

	Year Ended December 31,			
	2019		2018	
	Amount	Per BOE	Amount	Per BOE
Production taxes	$ 14,354	$ 1.83	$ 13,666	$ 2.17
Ad valorem taxes	4,722	0.60	5,382	0.85
Total production and ad valorem taxes	$ 19,076	$ 2.43	$ 19,048	$ 3.02

Depletion

Depletion expense increased by $19.3 million to $78.2 million for the year ended December 31, 2019 from $58.8 million for the year ended December 31, 2018. The increase resulted primarily from higher production levels and an increase in net book value on new reserves added.

General and Administrative Expenses

For the years ended December 31, 2019 and 2018, we incurred general and administrative expenses of $7.5 million and $8.0 million, respectively. The decrease of $0.5 million in general and administrative expenses for the year ended December 31, 2019 as compared to 2018 was primarily due to higher legal expenses in 2018 related to the change in tax structure that took place in March 2018 coupled with a slight decrease in unit-based compensation expense in 2019. These decreases were partially offset by an increase in expenses allocated from our general partner under our partnership agreement. For the years ended December 31, 2019 and 2018, our general partner received reimbursements from us of $3.1 million and $2.5 million, respectively.

Net Interest Expense

Net interest expense for the years ended December 31, 2019 and 2018 was $21.1 million and $13.8 million, respectively. The increase of $7.2 million in net interest expense for the year ended December 31, 2019 as compared to 2018 was due to increased borrowings and the issuance of senior notes during the year ended 2019.

Benefit From Income Taxes

We recorded an income tax benefit of $41.6 million and $72.4 million for the years ended December 31, 2019 and 2018, respectively. The change in our income tax provision was primarily due to a deferred benefit recognized during the year ended December 31, 2018 as a result of our change in federal income tax status. Prior to the second quarter of 2018, we had no provision for or benefit from income taxes. Total income tax benefit for the years ended December 31, 2019 and 2018 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the periods primarily due to deferred taxes recognized as a result of the Partnership's change in tax status and due to net income attributable to the non-controlling interest.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA in evaluating cash flow that will be available to pay distributions to our common unitholders.

We define Adjusted EBITDA as net income (loss) plus interest expense, net, non-cash unit-based compensation expense, depletion expense, (gain) loss on revaluation of investment and benefit from income taxes. Adjusted EBITDA is not a measure of net income as determined by GAAP. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss), royalty income, cash flow from operating activities or any other measure of financial performance or liquidity presented as determined in accordance with GAAP. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDA, to net income, our most directly comparable GAAP financial measure for the periods indicated:

	Year Ended December 31,	
	2019	**2018**
	(in thousands)	
Net income	$ 221,210	$ 262,877
Interest expense, net	21,076	13,849
Non-cash unit-based compensation expense	1,822	2,763
Depletion	78,178	58,830
(Gain) loss on revaluation of investment	(4,832)	550
Benefit from income taxes	(41,582)	(72,365)
Consolidated Adjusted EBITDA	275,872	266,504
EBITDA attributable to non-controlling interest	(151,498)	(125,616)
Adjusted EBITDA attributable to Viper Energy Partners LP	$ 124,374	$ 140,888

Non-GAAP Financial Measures

Gross oil, natural gas, and natural gas liquids sales and net sales prices

Revenues and gathering and transportation expenses related to production are reported net in our financial statements under GAAP. This impacts the comparability of prior periods and certain operating metrics, such as per-unit sales prices, as those metrics are prepared in accordance with GAAP using the net presentation for some revenues and the gross presentation for other metrics, and those periods prior to the fourth quarter of 2018. In order to provide metrics consistent with management's assessment of our operating results, we have presented both net (GAAP) and gross (non-GAAP) oil, natural gas, and natural gas liquid sales and the gross sales price. The gross sales price (non-GAAP), is calculated by using the net oil, natural gas, and natural liquid gas net revenues plus gathering and transportation expenses divided by the sales volumes. We believe presenting our gross revenues and sales prices allows for a useful comparison of net and gross sales prices for prior periods.

The following table presents a reconciliation of net oil, natural gas and natural gas liquids sales (GAAP) to gross oil, natural gas and natural gas liquids sales (non-GAAP) for the periods indicated:

	Year Ended December 31, 2019			
(in thousands)	Oil	Natural gas	Natural gas liquids	Total
Net oil, natural gas and natural gas liquids sales (GAAP)	$ 264,376	$ 8,092	$ 21,343	$ 293,811
Plus: Gathering and transportation expenses	1,328	1,589	1,448	4,365
Gross oil, natural gas and natural gas liquids sales (non-GAAP)	$ 265,704	$ 9,681	$ 22,791	$ 298,176
Sales volumes (MBbl/MMcf/MBbl/MBOE)	5,123	7,657	1,459	7,858
Gross sales price (non-GAAP)	$ 51.87	$ 1.26	$ 15.62	$ 37.94

	Year Ended December 31, 2018			
(in thousands)	Oil	Natural gas	Natural gas liquids	Total
Net oil, natural gas and natural gas liquids sales (GAAP)	$ 246,922	$ 12,976	$ 22,763	$ 282,661
Plus: Gathering and transportation expenses	765	848	830	2,443
Gross oil, natural gas and natural gas liquids (non-GAAP)	$ 247,687	$ 13,824	$ 23,593	$ 285,104
Sales volumes (MBbl/MMcf/MBbl/MBOE)	4,399	5,840	933	6,305
Gross sales price (non-GAAP)	$ 56.30	$ 2.37	$ 25.30	$ 45.22

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings and borrowings under our credit agreement, and our primary uses of cash have been, and are expected to continue to be, distributions to our unitholders and replacement and growth capital expenditures, including the acquisition of oil and natural gas interests. We intend to finance potential future acquisitions through a combination of cash on hand, borrowings under our credit agreement and, subject to market conditions and other factors, proceeds from one or more capital market transactions, which may include debt or equity offerings. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices and general economic, financial, competitive, legislative, regulatory and other factors, including weather.

The board of directors of our general partner has adopted a policy pursuant to which the Operating Company will distribute all of the available cash it generates each quarter to unitholders (including us), and we, in turn, will distribute all of the available cash we receive from the Operating Company to our common unitholders.

Cash distributions are made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for us and the Operating Company for each quarter is determined by the board of directors of our general partner following the end of such quarter. Available cash for the Operating Company for each quarter will generally equal its Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and 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, and our available cash will generally equal our Adjusted EBITDA (which will be our proportionate share of the available cash distributed to us by the Operating Company), less as a result of the Tax Election, cash needed for the payment of income taxes payable by us, if any.

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.

The following table presents cash distributions approved by the board of directors of our general partner for the periods presented:

Declaration Date	Quarter	Amount per Common Unit		Payment Date	Amount Distributed to Diamondback	
					(in thousands)	
April 28, 2017	Q1 2017	$	0.302	May 25, 2017	$	21,880
July 28, 2017	Q2 2017	$	0.332	August 24, 2017	$	24,286
October 16, 2017	Q3 2017	$	0.337	November 14, 2017	$	24,652
January 31, 2018	Q4 2017	$	0.460	February 26, 2018	$	33,649
April 5, 2018	Q1 2018	$	0.480	April 27, 2018	$	35,112
July 27, 2018	Q2 2018	$	0.600	August 20, 2018	$	43,901
October 23, 2018	Q3 2018	$	0.580	November 19, 2018	$	42,447
January 30, 2019	Q4 2018	$	0.510	February 25, 2019	$	37,326
April 25, 2019	Q1 2019	$	0.380	May 20, 2019	$	27,817
July 28, 2019	Q2 2019	$	0.470	August 21, 2019	$	34,400
October 25, 2019	Q3 2019	$	0.460	November 15, 2019	$	33,668
February 7, 2020	Q4 2019	$	0.450	February 28, 2020		*

* The Q4 2019 distribution is payable on February 28, 2020 to unitholders of record at the close of business on February 21, 2020. Based on the common units and Operating Company units held by Diamondback on February 11, 2020, the Q4 2019 distribution payable to Diamondback on February 28, 2020 will be approximately $41.1 million.

2019 Equity Offering

In March 2019, we completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 54% of our total units then outstanding. We received net proceeds from this offering of approximately $340.6 million, after deducting underwriting discounts and commissions and estimated offering expenses. We used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the outstanding borrowings under the Operating Company's revolving credit facility and finance acquisitions during the period.

2019 Senior Notes Offering

In October 2019, we completed an offering of our 5.375% Senior Notes due 2027 in the aggregate principal amount of $500.0 million. We received net proceeds of approximately $490.0 million from the Notes Offering. We loaned the gross proceeds of the Notes Offering to the Operating Company. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility.

2018 Equity Offering

In July 2018, we completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 59% of our total units then outstanding. We received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and estimated offering expenses. We used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the outstanding borrowings under the Operating Company's revolving credit facility.

Cash Flows

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

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Cash Flow Data:		
Net cash provided by operating activities	$ 236,691	$ 244,493
Net cash used in investing activities	(530,572)	(614,253)
Net cash provided by financing activities	274,807	368,239
Net decrease in cash	$ (19,074)	$ (1,521)

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. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

Investing Activities

Net cash used in investing activities was $530.6 million and $614.3 million during the years ended December 31, 2019, and 2018, respectively, related to acquisitions of oil and natural gas interests and land.

Financing Activities

Net cash provided by financing activities was $274.8 million during the year ended December 31, 2019, primarily related to the issuance of $500.0 million of our senior notes and net proceeds of $340.6 million from our public offerings of common units, partially offset by net repayment of $314.5 million of borrowings under the Operating Company's revolving credit facility and distributions of $240.4 million to our unitholders during 2019.

Net cash provided by financing activities was $368.2 million during the year ended December 31, 2018, primarily related to proceeds from net borrowings of $317.5 million under the Operating Company's revolving credit facility and net proceeds of $303.1 million from our public offering of common units, partially offset by distributions of $253.5 million to our unitholders during 2018.

The Operating Company's Revolving Credit Facility

On July 20, 2018, we, as guarantor, entered into an amended and restated credit agreement with the Operating Company, as borrower, Wells Fargo, as administrative agent, and the other lenders. The credit agreement, as amended to the date hereof, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on our oil and natural gas reserves and other factors of $775.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. Upon closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million. Effective October 8, 2019, in connection with the commencement of the Notes Offering described in this report, we entered into a third amendment to the Operating Company's revolving credit facility, which provided for the waiver of the automatic reduction of the borrowing base that would otherwise have occurred upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or us from $400.0 million to $1.0 billion.

The Partnership funded the cash portion of the purchase price for the Drop-Down Acquisition through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility. Additionally, in connection with our fall redetermination in November 2019, the borrowing base under the Operating Company's revolving credit facility was increased to $775.0 million. As of December 31, 2019, the borrowing base was set at $775.0 million, and we had $96.5 million of outstanding borrowings and $678.5 million available for future borrowings under the Operating Company's revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee 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 of November 1, 2022. The loan is secured by substantially all of our and our subsidiary's assets.

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 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

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, 2019, the Operating Company was in compliance with all financial 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 our credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Notes Offering

On October 16, 2019, we completed an offering of our 5.375% Senior Notes due 2027 in the aggregate principal amount of $500.0 million. We received net proceeds of approximately $490.0 million from the Notes Offering. We loaned the gross proceeds of the Notes Offering to the Operating Company. The Operating Company used the proceeds from the Notes Offering to repay then outstanding borrowings under its revolving credit facility.

The senior notes were issued under an indenture, dated as of October 16, 2019, among the Partnership, as issuer, the Operating Company, as guarantor and Wells Fargo Bank, National Association, as trustee. Pursuant to the indenture governing the senior notes (which we refer to as the indenture), interest on the senior notes accrues at a rate of 5.375% per annum on the outstanding principal amount thereof from October 16, 2019, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2020. The senior notes will mature on November 1, 2027.

The senior notes are our senior unsecured obligations and rank equally in right of payment with all of our existing and future senior indebtedness and senior in right of payment to any of the Partnership's future subordinated indebtedness. The Operating Company is guaranteeing the senior notes pursuant to the indenture. Neither Diamondback nor our general partner will guarantee the senior notes. All of our future restricted subsidiaries that either guarantee the Operating Company's revolving credit facility or certain other debt or are classified as domestic restricted subsidiaries under the indenture will also guarantee the senior notes. The guarantee ranks equally in right of payment with all of the existing and future senior unsecured indebtedness of the Operating Company and senior in right of payment to any future subordinated indebtedness of the Operating Company. The senior notes and the guarantee are effectively subordinated to all of our and the Operating Company's secured indebtedness (including all borrowings and other obligations under the Operating Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and will be structurally subordinated to all indebtedness and other liabilities, including trade payables, of any of our subsidiaries that do not guarantee the senior notes (other than liabilities owed to us).

We may on any one or more occasions redeem some or all of the senior notes at any time on or after November 1, 2022 at the redemption prices listed in the indenture. Prior to November 1, 2022, we may on any one or more occasions redeem all or a portion of the senior notes at a price equal to 100% of the principal amount of the senior notes plus a "make-whole" premium and accrued and unpaid interest to the redemption date. In addition, any time prior to November 1, 2022, we may on any one or more occasions redeem senior notes in an aggregate principal amount not to exceed 40% of the aggregate principal amount of the senior notes issued prior to such date at a redemption price of 105.375%, plus accrued and unpaid interest to the redemption date, with an amount not greater than the net cash proceeds from certain equity offerings.

If we experience a change of control (as defined in the indenture), we will be required to make an offer to repurchase the senior notes at a price equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to but not including the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the Indenture, we will be required to use the remaining proceeds to make an offer to repurchase the senior notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

The indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of its restricted subsidiaries to incur or guarantee additional indebtedness or issue certain redeemable or preferred equity, make certain investments, declare or pay dividends or make distributions on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness, transfer or sell assets including equity of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens and designate certain of our subsidiaries as unrestricted subsidiaries. Certain of these covenants are subject to termination upon the occurrence of certain events.

Intercompany Promissory Note

In connection with and upon closing of the Notes Offering, we loaned the gross proceeds from the Notes Offering to the Operating Company under the terms of that certain Subordinated Promissory Note, dated as of October 16, 2019, by the Operating Company in favor of us, which we refer to as the Intercompany Promissory Note. The Intercompany Promissory Note requires the Operating Company to repay the underlying loan to us on the same terms and in the same amounts as the senior notes and has the same maturity date, interest rate, change of control repurchase and redemption provisions. Our right to receive payment under the Intercompany Promissory Note is contractually subordinated to the Operating Company's guarantee of the notes and is structurally subordinated to all of the Operating Company's secured indebtedness (including all borrowings and other obligations under the Operating Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness.

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2019:

	Payments Due by Period				
	Total	2020	2021-2022	2023-2024	Thereafter
	(in thousands)				
Credit agreement[(1)]	$ 96,500	$ —	$ 96,500	$ —	$ —
Commitment fees under our credit agreement[(2)]	7,214	2,544	4,670	—	—
Senior Notes	500,000	—	—	—	500,000
Interest expense related to the senior notes[(3)]	210,582	26,875	53,750	53,750	76,207
	$ 814,296	$ 29,419	$ 154,920	$ 53,750	$ 576,207

(1) Includes the outstanding principal amount under the credit agreement, the table does not include interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged.

(2) This table reflects only the minimum amount of commitment fees due, which as of December 31, 2019 includes a commitment fee equal to 0.375% per year of the unused portion of the borrowing base of our credit agreement. The table does not include interest expense as we cannot predict the timing of future borrowings and repayments or interest rates to be charged. See Note 5–Debt to our consolidated financial statements and related notes included elsewhere in this Annual Report.

(3) Interest represents the scheduled cash payments on the senior notes.

Critical Accounting Policies

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. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See the notes to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding these accounting policies.

Use of Estimates

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. Actual results could differ from those estimates.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. 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. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, unit–based compensation and estimate of income taxes.

Method of Accounting for Oil and Natural Gas Properties

We account for 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. 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 plus estimated future development costs are amortized over total proved reserves.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment.

We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Impairment

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, impairment and deferred income taxes exceed the discounted future net revenues of proved oil and natural gas reserves, less any related income tax effects, the excess capitalized costs are charged to expense. In calculating future net revenues, prices are calculated as the average oil and natural gas prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of-the-month prices for the prior 12-month period, adjusted for any contract provisions and costs used are those as of the end of the appropriate quarterly period.

Oil and Natural Gas Reserve Quantities and Standardized Measure of Discounted Future Net Cash Flows

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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. 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. 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 amortization of capitalized costs and result in impairment of assets that may be material.

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.

Royalty Interest and Revenue Recognition

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 interest and revenue recognition related accounting policies are defined and described more fully in Note 2—Summary of Significant Accounting Policies to our consolidated financial statements included elsewhere in this Annual Report.

Accounting for Unit-Based Compensation

Unit-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. The LTIP and related accounting policies are defined and described more fully in Note 7—Unit-Based Compensation to our consolidated financial statements included elsewhere in this Annual Report. The Partnership estimates the fair value of phantom units as the closing price of the Partnership’s common units on the grant date of the award, which is expensed over the applicable vesting period.

Income Taxes

Prior to May 10, 2018, we were treated as a pass-through entity for federal income tax purposes. On May 10, 2018, we elected to be treated as a corporation for U.S. federal income tax purposes. 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.

We are subject to margin tax in the state of Texas pursuant to a tax sharing agreement with Diamondback, as discussed further in Note10—Income Taxes of our consolidated financial statements included elsewhere in the Annual Report. In addition to the 2019 and 2018 tax years, our 2016 and 2017 tax years, during which we were treated as a pass-through entity for federal income tax purposes, remain open to examination by tax authorities. As of December 31, 2019 and 2018, we had no unrecognized tax benefits that would have a material impact on the effective tax rate. We are continuing our 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, 2019 and 2018, there was no interest or penalties associated with uncertain tax positions recognized in our consolidated financial statements.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019 and 2018. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and our operators do experience inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which our properties are located.

Recent Accounting Pronouncements

For information regarding recent accounting pronouncements, See Note2—Summary of Significant Accounting Policies included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

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 pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable, particularly during the past year, and we expect this volatility to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control.

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 several significant purchasers. 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, Inc. (16%) and Shell Trading (US) Company, or Shell Trading (12%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (31%), Concho Resources, Inc. (16%) and Trafigura Trading LLC (11%). For the year ended December 31, 2017, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (47%) and RSP Permian LLC (23%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

If we enter into hedging arrangements with respect to oil and natural gas production from our properties, we will expose ourselves to credit risk, which is the failure of the courterparty to perform under the terms of the arrangement.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our credit agreement. The terms of our credit agreement provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of the loans outstanding in relation to the borrowing base. We entered into this credit agreement on July 8, 2014, as subsequently amended and restated, and as of December 31, 2019, we had $96.5 million in outstanding borrowings. Our weighted average interest rate was 4.3%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $1.0 million based on the $96.5 million outstanding in the aggregate under our credit agreement on December 31, 2019.

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, 2019, 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, 2019, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2019 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, 2019.

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, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Partnership’s internal control over financial reporting at December 31, 2019, is included in this Item under the heading “Report of Independent Registered Public Accounting Firm.”

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
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 (collectively, the "Partnership") as of December 31, 2019, 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, 2019, 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, 2019, and our report dated February 18, 2020 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 18, 2020

ITEM 9B. OTHER INFORMATION

On February 11, 2020, we issued an earnings release reporting our financial and operating results for the fourth quarter and full year ended December 31, 2019, which earnings release was furnished to the SEC as Exhibit 99.1 to our Current Report on Form 8-K on February 11, 2020. The earnings release inadvertently included an error in certain balance sheet data as of December 31, 2019 that primarily impacted three line items in the balance sheet and related totals. Specifically, the correct value of oil and natural gas interests as of December 31, 2019 was $2,868.5 million (rather than $2,946.8 million stated in the earnings release), the deferred tax asset was $142.5 million (rather than $125.8 million stated in the earnings release) and the book amount of common unitholders' equity was $929.1 million (rather than $1,017.2 million stated in the earnings release). This inadvertent error had no other impact on our financial statements or operating results reported in the earnings release and we do not believe it to be material. The correct balance sheet as of December 31, 2019 is included in this report and a corrected earnings release is posted on our website at www.viperenergy.com under the "Investors" tab under "News/Events-Press Releases."

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 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 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 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, 2020. 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. There are no family relationships among any of our directors or executive officers.

Name	Age	Position With Our General Partner
Travis D. Stice	58	Chief Executive Officer and Director
Kaes Van't Hof	33	President
Teresa L. Dick	50	Chief Financial Officer, Executive Vice President and Assistant Secretary
Russell Pantermuehl	60	Executive Vice President and Chief Engineer
Thomas F. Hawkins	65	Executive Vice President—Land
Matt Zmigrosky	41	Executive Vice President, General Counsel and Secretary
Steven E. West	59	Chairman of the Board
W. Wesley Perry	63	Director
Spencer D. Armour	65	Director
James L. Rubin	35	Director
Rosalind Redfern Grover	78	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 33 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 33-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 eight 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.

Russell Pantermuehl. Mr. Pantermuehl has served as Executive Vice President and Chief Engineer since March 2019. Mr. Pantermuehl served as Executive Vice President—Reservoir Engineering of our general partner since February 2017 to February 2019 and served as Vice President—Reservoir Engineering from February 2014 to February 2017. He has also served as Diamondback's Executive Vice President—Reservoir Engineering since February 2017, and served as Vice President-Reservoir Engineering from August 2011 to February 2017. Prior to his positions with us and Diamondback, Mr. Pantermuehl served as a reservoir engineering supervisor for Concho Resources Inc., an oil and gas exploration company, from March 2010 to August 2011. Mr. Pantermuehl worked for ConocoPhillips Company as a reservoir engineering advisor from January 2005 to March 2010. Mr. Pantermuehl also worked as an independent consultant in the oil and gas industry from March 2000 to December 2004. He received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

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 nearly 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 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 President 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

The board of directors of our general partner has six directors, four of whom are independent as defined under the independence standards established by Nasdaq and the Exchange Act. Steven E. West, W. Wesley Perry, 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 or to 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.

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 chairman of the board of Diamondback. Our general partner's board of directors has determined that the combined roles of chairman of the board of directors of our general partner and chairman of the board 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, 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 2019, the board of directors of our general partner meteight times. Each director attended at least75% of the meetings of the board and the committees of the board on which he or she served that occurred during 2019.

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. 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 2019 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 2020 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 2020 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 2019, 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). In addition, on March 1, 2019, our general partner granted 11,001 phantom units to Mr. Zmigrosky under the LTIP in connection with his appointment as the Executive Vice President, General Counsel and Secretary of our general partner, vesting in three equal installments beginning on March 1, 2019.

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 proceeding the date of grant. The awards vest on the first anniversary of the grate 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 2019 for their services on the board:

Name	Fees Earned or Paid in cash(a)	Unit Awards(b)	Total
Spencer D. Armour[(c)(d)(e)]	$ 75,000	$ 104,094	$ 179,094
Rosalind Redfern Grover[(c)(d)(e)]	$ 75,000	$ 104,094	$ 179,094
W. Wesley Perry[(c)(d)(e)]	$ 85,000	$ 104,094	$ 189,094
James L. Rubin[(c)(d)(e)]	$ 60,000	$ 104,094	$ 164,094
Steven E. West[(c)(d)(e)]	$ 60,000	$ 104,094	$ 164,094

(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 6,414 phantom units on July 25, 2017, which vested and settled on July 1, 2018, pursuant to the LTIP, with each unit having a grant date fair value of $16.78. 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 3,063 phantom units on July 10, 2018, which vested and settled on July 10, 2019, pursuant to the LTIP, with each unit having a grant date fair value of $34.33. Each phantom unit is the economic equivalent of one of our common units.

(e) Each of Ms. Grover and Messrs. Armour, Perry, Rubin and West received a grant of 3,257 phantom units on July 10, 2019, which will vest and settle on July 10, 2020, pursuant to the LTIP, with each unit having a grant date fair value of $31.96. 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 2020 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's2020 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 ofJanuary 31, 2020 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%
Viper Energy Partners GP LLC	—	—
Travis D. Stice(2)	112,448	*
Kaes Van't Hof(3)	39,624	*
Teresa L. Dick	11,540	*
Russell Pantermuehl	48,487	*
Thomas F. Hawkins	—	—
Matt Zmigrosky(4)	6,247	*
Steven E. West(5)	59,550	*
W. Wesley Perry(5)	45,505	*
Spencer D. Armour(5)	9,477	*
James L. Rubin(6)	—	—
Rosalind Redfern Grover(5)	19,839	*
All directors and executive officers as a group (11 persons)	352,717	*

* 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, 2020 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, 2020 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 67,805,707 common units outstanding as of January 31, 2020. 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, 2020 or within 60 days of January 31, 2020. 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. Includes 16,011 phantom units that are scheduled to vest on February 16, 2020.

(3) Includes 23,136 phantom units that are scheduled to vest on February 16, 2020.

(4) Includes 3,667 phantom units that are scheduled to vest on March 1, 2020. Excludes 3,667 phantom units that are scheduled to vest on March 1, 2021.

(5) Excludes 3,257 phantom units that are scheduled to vest on July 10, 2020.

(6) Excludes 26,505 common units (representing vested phantom units previously granted to Mr. Rubin) and 3,257 phantom units that are scheduled to vest on July 10, 2020, 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, 2020, 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.

	Shares of Diamondback Common Stock Beneficially Owned(1)	
Name of Beneficial Owner	**Amount and Nature of Beneficial Ownership**	**Percentage of Class**
Travis D. Stice(2)	392,042	*
Kaes Van't Hof(3)	13,548	*
Teresa L. Dick(4)	37,547	*
Russell Pantermuehl(5)	96,980	*
Thomas F. Hawkins(6)	12,710	*
Matt Zmigrosky(7)	4,054	*
Steven E. West(8)	7,461	*
W. Wesley Perry	—	—
Spencer D. Armour	—	—
James L. Rubin	—	—
Rosalind Redfern Grover	—	—
All directors and executive officers as a group (11 persons)	564,342	*

* 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, 2020 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, 2020, 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 67,805,707 shares of common stock outstanding as of January 31, 2020. 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, 2020 or within 60 days of January 31, 2020. 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 6,797 restricted stock units that are scheduled to vest on February 21, 2020 and (ii) 10,986 restricted stock units that are scheduled to vest on March 1, 2020. Excludes 10,986 restricted stock units that are scheduled to vest on March 1, 2021. Also excludes (i) 44,460 performance-based restricted stock units awarded to Mr. Stice on February 16, 2017 that will vest effective December 31, 2019 (representing 200% vesting of the originally reported amount) subject to 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, 2019 by Diamondback's compensation committee, (ii) 30,585 performance-based restricted stock units awarded to Mr. Stice on February 13, 2018, 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 December 31, 2020 and (iii) 49,436 performance-based restricted stock units awarded to Mr. Stice on March 1, 2019, 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, 2021.

(3) Includes (i) 1,333 restricted stock units that are scheduled to vest on February 21, 2020 and (ii) 5,127 restricted stock units that are scheduled to vest on March 1, 2020. Excludes (i) 5,127 restricted stock units that are scheduled to vest on March 1, 2021, (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 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, 2021 and (iv) 13,183 performance-based restricted stock units awarded on March 1, 2019 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, 2021 and are scheduled vest in five equal installments beginning on March 1, 2025.

(4) Includes (i) 1,866 restricted stock units that are scheduled to vest on February 21, 2020 and (ii) 2,930 restricted stock units that are scheduled to vest on March 1, 2020. Excludes 2,930 restricted stock units that are scheduled to vest on March 1, 2021. Also excludes (i) 11,700 performance-based restricted stock units awarded to Ms. Dick on February 16, 2017 that will vest effective December 31, 2019 (representing 200% vesting of the originally reported amount) subject to 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, 2019 by Diamondback's compensation committee, (ii) 8,396 performance-based restricted stock units awarded to Ms. Dick on February 13, 2018, 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 December 31, 2020 and (iii) 13,183 performance-based restricted stock units awarded to Ms. Dick on March 1, 2019, 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, 2021.

(5) Includes (i) 3,412 restricted stock units that are scheduled to vest on February 21, 2020 and (ii) 5,127 restricted stock units that are scheduled to vest on March 1, 2020. Excludes 5,127 restricted stock units that are scheduled to vest on March 1, 2021. Also excludes (i) 23,400 performance-based restricted stock units awarded to Mr. Pantermuehl on February 16, 2017 that will vest effective December 31, 2019 (representing 200% vesting of the originally reported amount) subject to 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, 2019 by Diamondback's compensation committee, (ii) 15,353 performance-based restricted stock units awarded to Mr. Pantermuehl on February 13, 2018, 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, 2020 and (iii) excludes 23,070 performance-based restricted stock units awarded to Mr. Pantermuehl on March 1, 2019, 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, 2021.

(6) Includes (i) 1,280 restricted stock units that are scheduled to vest on February 21, 2020 and (ii) 1,905 restricted stock units that are scheduled to vest on March 1, 2020. Excludes 1,905 restricted stock units that are scheduled to vest on March 1, 2021. Also excludes 8,569 performance-based restricted stock units awarded to Mr. Hawkins on March 1, 2019 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, 2021.

(7) Includes 2,344 restricted stock units that are scheduled to vest on March 1, 2020. Excludes 2,344 restricted stock units that are scheduled to vest on March 1, 2021. Also excludes 10,546 performance-based restricted stock units awarded to Mr. Zmigrosky on March 1, 2019 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, 2021.

(8) Excludes 1,830 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 2020 annual meeting of stockholders of Diamondback.

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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, 2020 by each unitholder known by us to beneficially own of 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	1.1%	90,709,946	100%
Wellington Management Group LLP c/o Wellington Management Company LLP 280 Congress Street Boston, MA 02210	9,179,000(3)	13.5%	—	—
FMR LLC 245 Summer Street Boston, MA 02210	7,651,509(4)	11.3%	—	—
Santa Elena Minerals, LP(5) 400 W. Illinois, Suite 1300 Midland, TX 79701	5,152,124	7.6%	—	—
Goldman Sachs Asset Management(6) 200 West Street New York, NY 10282	4,431,694(7)	6.5%	—	—
Capital World Investors 333 South Hope Street Los Angeles, CA 90071	3,721,763(8)	5.5%	—	—

(1) Beneficial ownership is determined in accordance with SEC rules. The percentage of common units beneficially owned is based on 67,805,707 common units outstanding as of January 31, 2020. 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 81,765,429 Class B units directly. Diamondback also has the beneficial ownership of 8,944,517 Class B units, which are held by Energen Resources Corporation, its indirect wholly-owned subsidiary ("Energen Resources"). An aggregate of 90,709,946 Class B units, together with the same aggregate number of units of the Operating Company (each, an "OpCo unit"), held by Diamondback and Energen Resources, are exchangeable from time to time, in their 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 directly. Diamondback also has shared voting and dispositive power of 8,944,517 Class B units held by Energen Resources, which represent approximately 9.9% of the outstanding Class B units. The directors of Diamondback are Travis D. Stice, Steven E. West, Michael P. Cross, David L. Houston, Mark L. Plaumann and Melanie M. Trent. Travis D. Stice is the sole director of Energen Resources.

(3) Based solely on Schedule 13G/A jointly filed with the SEC on January 8, 2020 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, 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 8,953,150 common units and shared dispositive power over 9,179,000 common units. Wellington Company reported shared voting power over 8,675,619 common units and shared dispositive power over 8,780,576 common units.

(4) Based solely on Schedule 13G/A jointly filed with the SEC on February 7, 2020 by FMR LLC ("FMR") and Abigail P. Johnson. Ms. Johnson is a Director, the Chairman and the Chief Executive Officer of FMR. Members of the Johnson family, including Abigail P. Johnson, are the predominant owners, directly or through trusts, of 49% of the voting power of FMR. Members of the Johnson family may be deemed to form a controlling group with respect to FMR. Neither FMR nor Ms. Johnson has the sole power to vote or direct the voting of the common units owned directly by the various investment companies ("Fidelity Funds") advised by Fidelity Management & Research Company ("FMR Co."), a wholly owned subsidiary of FMR, which power resides with the Fidelity Funds' Boards of Trustees. FMR Co. carries out the voting of the common units under written guidelines established by the Fidelity Funds' Boards of Trustees. FMR reported sole voting power over 189,187 common units and sole dispositive power over 7,651,509 common units. Ms. Johnson reported sole dispositive power over 7,651,509 common units. Various persons have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of common units. FMR Co. Inc. beneficially owns more than 5% of the common units.

(5) Based on Viper's records.

(6) Goldman Sachs Asset Management, L.P. together with GS Investment Strategies, LLC reported as "Goldman Sachs Asset Management."

(7) Based solely on Schedule 13G filed with the SEC on January 31, 2020 by Goldman Sachs Asset Management. Goldman Sachs Asset Management reported shared voting power with respect to 4,261,361 common units and shared dispositive power with respect to 4,431,694 common units.

(8) Based solely on Schedule 13G filed with the SEC on February 14, 2020 by Capital World Investors. Capital World Investors reported sole voting power over 3,721,763 common units and sole dispositive power over 3,721,763 common units.

Securities Authorized For Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2019:

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	95,248	$ —	8,797,670

(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

The following sets forth information with respect to the treatment of the unvested equity awards, which were granted to the executive officers of our general partner and were outstanding as of December 31, 2019 under the LTIP, in connection with certain termination events, including a termination related to a change of control of Viper or Diamondback.

Under the terms of Mr. Stice's employment agreement with Diamondback and the terms of the phantom unit awards made to Mr. Stice under the LTIP, all unvested phantom unit awards granted to Mr. Stice will accelerate and immediately vest upon (i) the change of control of Viper or Diamondback, provided that Diamondback is the sole general partner of Viper, (ii) Mr.

Stice's termination without cause, (iii) Mr. Stice's resignation for good reason or (iv) Mr. Stice's death or disability. As of December 31, 2019, Mr. Stice held 16,011 unvested phantom units granted under the LTIP, all which are scheduled to vest on February 16, 2020, and had a value of $394,831 as of December 31, 2019.

Under the terms of Mr. Van't Hof's and Mr. Zmigrosky's phantom unit awards made to these executive officers of our general partner under the LTIP, all of their unvested phantom unit awards will accelerate and immediately vest upon the change of control of Viper or Diamondback, provided that Diamondback is the sole general partner or Viper, or upon such executive officer's death or disability. As of December 31, 2019, Mr. Van't Hof held 23,136 unvested phantom units granted under the LTIP, all of which are scheduled to vest on February 16, 2020, and had a value of $570,534 as of December 31, 2019, and Mr. Zmigrosky held 7,334 unvested phantom units granted under the LTIP, of which 3,667 phantom units are scheduled to vest on March 1, 2020 and 3,667 phantom units are scheduled to vest on March 1, 2021, and had an aggregate value of $180,856 as of December 31, 2019.

No other executive officers of our general partner held equity awards under the LTIP as of December 31, 2019.

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, 2019, our general partner received $3.1 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 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, 2019, Diamondback received distributions from us and the Operating Company in the aggregate amount of $133.2 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, 2019, we did not accrue any state income tax expense.

Lease Bonus Payments

During the year ended December 31, 2019, Diamondback paid us $0.3 million in lease bonus payments to extend the term of six leases and $0.2 million in lease bonus payments for four new leases.

Drop-Down Acquisitions

On October 1, 2019, we completed the acquisition of certain mineral and royalty interests from subsidiaries of Diamondback. See "Management Discussion and Analysis—2019 Transactions and Recent Developments—Drop-Down Acquisition for additional information.

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 ACCOUNTING 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, 2019 and 2018.

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, 2019 and 2018 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,	
	2019	2018
	(in thousands)	
Audit fees[(1)]	$ 322	$ 230
Audit-related fees[(2)]	89	—
Tax fees[(3)]	—	—
All other fees[(4)]	—	—
Total	$ 411	$ 230

(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:

1. Financial Statements

2. Financial Statement Schedules

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

3. Exhibits

Exhibit Number	Description
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	First Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
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 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).
4.1*	Description of Securities of the Partnership.
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	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).
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	Contribution Agreement, dated June 17, 2014, by and among Viper Energy Partners LLC, Viper Energy Partners GP LLC, Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.3+	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).
10.4	Advisory Services Agreement, dated June 23, 2014, by and among Viper Energy Partners LP, Viper Energy Partners GP LLC and Wexford Capital LP (incorporated by reference to Exhibit 10.3 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.5	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).

3. Exhibits

Exhibit Number	Description
10.6	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).
10.7+	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).
10.8+*	Form of Phantom Unit Agreement.
10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on September 30, 2019).
10.14	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 10, 2019).
10.15	Fourth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 29, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on December 5, 2019).
10.16	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, 2019, 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.

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 18, 2020

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 18, 2020
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)	February 18, 2020
/s/ Steven E. West Steven E. West	Director	February 18, 2020
/s/ W. Wesley Perry W. Wesley Perry	Director	February 18, 2020
/s/ Spencer D. Armour Spencer D. Armour	Director	February 18, 2020
/s/ James L. Rubin James L. Rubin	Director	February 18, 2020
/s/ Rosalind Redfern Grover Rosalind Redfern Grover	Director	February 18, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
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 (collectively, the "Partnership") as of December 31, 2019 and 2018, the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, 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 18, 2020 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 supporting 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 matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depletion expense, impairment evaluation and acquisition valuation of oil and gas properties

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 3 to the financial statements, the Partnership acquired significant mineral and/or royalty interests throughout 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, forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties, and for acquisitions that included proved developed producing properties using an estimated fair value pricing model for the valuation of 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. The impairment evaluation for the full cost method of accounting is the ceiling test, dependent upon the estimates of proved reserve volumes and future revenues, which we have identified as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Partnership's proved reserves could have a significant impact on the measurement of depletion expense or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of key controls relating to the preparation of the ceiling test calculation, management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Partnership's oil and gas properties for potential impairment, and management's estimation of the fair value of acquired mineral and/or 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 and the management review controls on information provided to the reservoir engineering specialists and the management review controls on the final proved reserve report 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.

- For acquisitions of mineral interests during the year in which proved developed producing properties are significant and 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. Specifically, our audit procedures involved testing management's assumptions as follows:

    - Analyzed the appropriateness of fair value pricing used in the acquisition reserve report to published product pricing on the acquisition closing date;

    - Evaluated the net revenue interests used in the acquisition reserve report by inspecting a sample of land and division order records;

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

    - Utilized valuation specialists to compare the acreage value allocated, on a per acre basis, to other recent acquisitions in the same or similar locations.

- 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.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2013.

Oklahoma City, Oklahoma
February 18, 2020

Viper Energy Partners LP
Consolidated Balance Sheets

	December 31,	
	2019	2018
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 3,602	$ 22,676
Royalty income receivable	58,089	38,823
Royalty income receivable—related party	10,576	3,489
Other current assets	397	257
Total current assets	72,664	65,245
Property:		
Oil and natural gas interests, full cost method of accounting ($1,551,767 and $871,485 excluded from depletion at December 31, 2019 and December 31, 2018, respectively)	2,868,459	1,716,713
Land	5,688	5,688
Accumulated depletion and impairment	(326,474)	(248,296)
Property, net	2,547,673	1,474,105
Deferred tax asset	142,466	96,883
Other assets	22,823	17,831
Total assets	$ 2,785,626	$ 1,654,064
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable—related party	$ 150	$ —
Accrued liabilities	13,282	6,022
Total current liabilities	13,432	6,022
Long-term debt, net	586,774	411,000
Total liabilities	600,206	417,022
Commitments and contingencies (Note 12)		
Unitholders' equity:		
General partner	889	1,000
Common units (67,805,707 units issued and outstanding as of December 31, 2019 and 51,653,956 units issued and outstanding as of December 31, 2018)	929,116	540,112
Class B units (90,709,946 units issued and outstanding as of December 31, 2019 and 72,418,500 units issued and outstanding December 31, 2018)	1,130	990
Total Viper Energy Partners LP unitholders' equity	931,135	542,102
Non-controlling interest	1,254,285	694,940
Total equity	2,185,420	1,237,042
Total liabilities and unitholders' equity	$ 2,785,626	$ 1,654,064

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Operations

	Year Ended December 31,		
	2019	2018	2017
	(In thousands, except per unit amounts)		
Operating income:			
Royalty income	$ 293,811	$ 282,661	$ 160,163
Lease bonus income	4,117	6,029	11,870
Other operating income	355	130	—
Total operating income	298,283	288,820	172,033
Costs and expenses:			
Production and ad valorem taxes	19,076	19,048	10,608
Gathering and transportation	—	—	789
Depletion	78,178	58,830	40,519
General and administrative expenses	7,489	7,955	6,296
Total costs and expenses	104,743	85,833	58,212
Income from operations	193,540	202,987	113,821
Other income (expense):			
Interest expense, net	(21,076)	(13,849)	(3,164)
Gain (loss) on revaluation of investment	4,832	(550)	—
Other income, net	2,332	1,924	821
Total other expense, net	(13,912)	(12,475)	(2,343)
Income before income taxes	179,628	190,512	111,478
Benefit from income taxes	(41,582)	(72,365)	—
Net income	221,210	262,877	111,478
Net income attributable to non-controlling interest	174,929	118,919	—
Net income attributable to Viper Energy Partners LP	$ 46,281	$ 143,958	$ 111,478
Net income attributable to common limited partner units:			
Basic	$ 0.75	$ 2.01	$ 1.07
Diluted	$ 0.75	$ 2.01	$ 1.07
Weighted average number of common limited partner units outstanding:			
Basic	61,744	71,546	104,318
Diluted	61,787	71,626	104,383

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, 2016	87,800	$ 547,898	—	$ —	$ —	$ —	$ 547,898
Net proceeds from the issuance of common units - public	25,175	369,896		—	—	—	369,896
Net proceeds from the issuance of common units - Diamondback	700	10,067		—	—	—	10,067
Common units issued for acquisition	175	3,050			—	—	3,050
Unit-based compensation	32	2,395		—	—	—	2,395
Distributions to public		(41,367)		—	—	—	(41,367)
Distributions to Diamondback		(89,509)		—	—	—	(89,509)
Net income		111,478		—	—	—	111,478
Balance at December 31, 2017	113,882	913,908	—	—	—	—	913,908
Impact of adoption of ASU 2016-01		(18,651)		—	—	—	(18,651)
Unit exchange related to tax conversion	(73,150)	(545,441)	73,150	1,000	1,000	545,441	2,000
Recapitalization related to tax conversion	732	—	(732)	(10)	—	—	(10)
Net proceeds from the issuance of common units - public	10,080	303,121		—	—	—	303,121
Unit-based compensation	103	2,763		—	—	—	2,763
Unit options exercised	8	140		—	—	—	140
Distributions to public		(98,333)		—	—	—	(98,333)
Distributions to Diamondback		(69,655)		—	—	(85,454)	(155,109)
Distributions to General Partner		(31)		—	—	—	(31)
Change in ownership of consolidated subsidiaries, net		(91,667)		—	—	116,034	24,367
Net income		143,958		—	—	118,919	262,877
Balance at December 31, 2018	51,654	$ 540,112	72,419	$ 990	$ 1,000	$ 694,940	$ 1,237,042

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	85	1,822	—	—	—	—	1,822
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
Units repurchased for tax withholding	(11)	(353)	—	—	—	—	(353)
Net income	—	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

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 221,210	$ 262,877	$ 111,478
Adjustments to reconcile net income to net cash provided by operating activities:			
Benefit from deferred income taxes	(41,582)	(72,516)	—
Depletion	78,178	58,830	40,519
(Gain) loss on revaluation of investment	(4,832)	550	—
Amortization of debt issuance costs	978	737	589
Non-cash unit-based compensation	1,822	2,763	2,395
Changes in operating assets and liabilities:			
Restricted cash	—	—	500
Royalty income receivable	(19,266)	(13,069)	(15,711)
Royalty income receivable—related party	(7,087)	1,653	(1,672)
Accounts payable and accrued liabilities	7,091	2,545	1,298
Accounts payable—related party	150	—	—
Income tax payable	169	151	—
Other current assets	(140)	(28)	(177)
Net cash provided by operating activities	236,691	244,493	139,219
Cash flows from investing activities:			
Acquisition of oil and natural gas interests	(530,572)	(610,131)	(344,079)
Acquisition of land	—	(4,687)	—
Proceeds from sale of assets	—	441	—
Proceeds from the sale of investments	—	124	—
Net cash used in investing activities	(530,572)	(614,253)	(344,079)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	590,500	691,500	278,500
Repayment on credit facility	(905,000)	(374,000)	(305,500)
Proceeds from senior notes	500,000	—	—
Debt issuance costs	(10,863)	(1,039)	(2,259)
Proceeds from public offerings	340,860	305,773	380,412
Public offering costs	(221)	(2,652)	(433)
Units purchased for tax withholding	(353)	—	—
Proceeds from exercise of unit options	—	140	—
Contributions by members	250	2,000	—
Distributions to partners	(240,366)	(253,483)	(130,876)
Net cash provided by financing activities	274,807	368,239	219,844
Net (decrease) increase in cash	(19,074)	(1,521)	14,984
Cash and cash equivalents at beginning of period	22,676	24,197	9,213
Cash and cash equivalents at end of period	$ 3,602	$ 22,676	$ 24,197

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Supplemental disclosure of cash flow information:			
Interest paid	$ 13,803	$ 12,438	$ 2,589
Supplemental disclosure of non—cash transactions:			
OpCo units issued for the Drop-Down transaction (Note 3)	$ 497,162	$ —	$ —
Common units issued for acquisition	$ 124,012	$ —	$ 3,050

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, the common units of which are listed on the Nasdaq Global Select Market under the symbol "VNOM". The Partnership was formed by Diamondback Energy, Inc. ("Diamondback"), on February 27, 2014 to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin and Eagle Ford Shale. Unless the context requires otherwise, references to "we," "us," "our" or "the Partnership" are intended to mean the business and operations of Viper Energy Partners LP and its consolidated subsidiary, Viper Energy Partners LLC.

As of December 31, 2019, a wholly-owned subsidiary of Diamondback, Viper Energy Partners GP LLC (the "General Partner"), held a 100% general partner interest in the Partnership and Diamondback had an approximate 58% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.

Recapitalization, Tax Status Election and Related Transactions

In March 2018, the Board of Directors of the General Partner unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election. In connection with making this election, on May 9, 2018 the Partnership (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of the Operating Company, (iii) amended and restated its existing registration rights agreement with Diamondback and (iv) entered into an exchange agreement with Diamondback, the General Partner and the Operating Company. Simultaneously with the effectiveness of these agreements, Diamondback delivered and assigned to the Partnership the 73,150,000 common units Diamondback owned in exchange for (i) 73,150,000 of the Partnership's newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018 (the "Recapitalization Agreement"). Immediately following that exchange, the Partnership continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and Diamondback owned the remaining approximately 64% of the outstanding units issued by the Operating Company. Upon completion of the Partnership's July 2018 offering of units, it owned approximately 41% of the outstanding units issued by the Operating Company and Diamondback owned the remaining approximately 59%. The Operating Company units and the Partnership's Class B units 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).

On May 10, 2018, the change in the Partnership's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) Diamondback made a cash capital contribution of $1.0 million to the Partnership in respect of the Class B units. Diamondback, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, Diamondback also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as the Partnership's general partner and Diamondback continues to control the Partnership. After the effectiveness of the tax status election and the completion of related transactions, the Partnership's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure was adopted to provide anticipated significant benefits to the Partnership's business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to the Partnership's Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and the Partnership's Current Report on Form 8-K filed with the SEC on May 15, 2018.

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.

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 at the date of the financial statements.

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, unit–based compensation and estimate 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.

Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2019	2018
	(In thousands)	
Interest payable	$ 6,718	$ 728
Ad valorem taxes payable	5,632	5,039
Other	932	255
Total accrued liabilities	$ 13,282	$ 6,022

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 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. For the year ended December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. 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.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, receivables, payables, a cost method investment, a credit agreement, and senior notes. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments. The fair value of the cost method investment is determined using the quoted market prices for those periods. The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Partnership for bank loans with similar terms and maturities. The fair value of the senior notes are determined using quoted market prices.

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, 2019 and 2018, 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 $9.95, $9.33 and $10.07 for the years ended December 31, 2019, 2018 and 2017, respectively. Depletion for oil and natural gas properties was $78.2 million, $58.8 million and $40.5 million for the years ended December 31, 2019, 2018 and 2017, 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. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2019, 2018 and 2017.

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 to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of$6.6 million, $5.5 million and $4.4 million, net of accumulated amortization of $3.1 million, $2.2 million and $1.4 million as of December 31, 2019, 2018 and 2017, respectively. The costs are associated with the Partnership's credit agreement and are being amortized over the term of the credit agreement.

Long-term debt included capitalized costs related to the senior notes of$2.5 million, net of accumulated amortization of $0.05 million, as of December 31, 2019. There wereno capitalized costs or accumulated amortization related to senior notes as ofDecember 31, 2018 or 2017. The costs associated with the senior notes are being netted against the senior notes balances and are being amortized over the term of the senior notes using the effective interest method.

Concentrations

The Partnership is subject to risk resulting from the concentration of the Partnership's royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. 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, Inc. (16%) and Shell Trading (US) Company ("Shell Trading") (12%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (31%), Concho Resources, Inc. (16%) and Trafigura Trading LLC (11%). For the year ended December 31, 2017, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (47%) and RSP Permian LLC (23%). 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.

Earnings Per Unit

Earnings per unit applicable to limited partners is computed by dividing limited partners' interest in net income by the weighted average number of outstanding common units.

Unit–Based Compensation

Unit–based compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period. See Note 7—Unit-Based Compensation.

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 subject to margin tax in the state of Texas pursuant to a tax sharing agreement with Diamondback, as discussed further in Note 10—Income Taxes. In addition to the 2019 and 2018 tax years, the Partnership's 2016 and 2017 tax years, during which the Partnership was organized as a pass-through entity for federal income tax purposes, remain open to examination by tax authorities. As of December 31, 2019 and 2018, the Partnership had no unrecognized tax benefits that would have a material impact on the effective tax rate. 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, 2019, 2018 and 2017, there was no interest or penalties associated with uncertain tax positions recognized in the Partnership's consolidated financial statements.

For the year ended December 31, 2019, the Partnership did not accrue any state income tax expense. For the year ended December 31, 2018, the Partnership accrued state income tax expense of $0.2 million, for its share of Texas margin tax for which the Partnership's results are included in a combined tax return filed by Diamondback. For the year ended December 31, 2017, no amount of Texas margin tax has been provided in the accompanying financial statements.

Viper Energy Partners LP
Notes to Consolidated Financial Statements - (Continued)

Recent Accounting Pronouncements

The Partnership considers the applicability and impact of all ASUs. ASUs not listed below were assessed and determined to be either not applicable or clarifications of ASUs previously disclosed. The following table provides a brief description of recent accounting pronouncements and the Partnership's analysis of the effects on its financial statements:

Standard	Description	Date of Adoption	Effect on Financial Statements or Other Significant Matters
Recently Adopted Pronouncements			
ASU 2016-13, "Financial Instruments - Credit Losses"	This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash.	Q1 2020	The Partnership adopted this update effective January 1, 2020. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity since it does not have a history of credit losses.
ASU 2018-13, "Fair Value Measurement (Topic 820) - Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement"	This update modifies the fair value measurement disclosure requirements specifically related to Level 3 fair value measurements and transfers between levels.	Q1 2020	The Partnership adopted this update effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity since it does not have transfers between fair value levels.
ASU 2018-15, "Intangibles - Goodwill and Other - Internal - Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract"	This update requires the capitalization of implementation costs incurred in a hosting arrangement that is a service contract for internal-use software. Training and certain data conversion costs cannot be capitalized. The entity is required to expense the capitalized implementation costs over the term of the hosting agreement.	Q1 2020	The Partnership adopted this update prospectively effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.
ASU 2019-05, "Financial Instruments-Credit Losses (Topic 326)"	This update allows a fair value option to be elected for certain financial assets, other than held-to-maturity debt securities, that were previously required to be measured at amortized cost basis.	Q1 2020	The Partnership adopted this update effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.
Pronouncements Not Yet Adopted			
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.	Q1 2021	This update is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Partnership does not believe the adoption of this standard will have an impact on its financial position, results of operations or liquidity.

3. ACQUISITIONS

2019 Activity

Drop-Down Acquisition

On October 1, 2019, we 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. In connection with the closing of the Drop-Down Acquisition, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million.

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 Recent 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.

As a result of the Drop-Down Acquisition, the Santa Elena Acquisition and the other recently completed acquisitions described above, as of December 31, 2019, the Partnership's assets included mineral interests representing 814,224 gross (24,304 net royalty) acres in the Permian Basin and the Eagle Ford Shale, approximately 50% of which are operated by Diamondback.

2018 Activity

During the year ended December 31, 2018, the Partnership acquired mineral interests from unrelated third parties underlying 3,585 net royalty acres for an aggregate of approximately $440.4 million and, as of December 31, 2018, had mineral interests underlying 14,841 net royalty acres. The Partnership funded these acquisitions primarily with cash on hand and borrowings under its revolving credit facility.

On August 15, 2018, the Partnership acquired mineral interests from Diamondback underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by Diamondback, for $175.0 million.

2017 Activity

During the year ended December 31, 2017, the Partnership acquired mineral interests underlying 3,157 net royalty acres for an aggregate of approximately $343.1 million and, as of December 31, 2017, had mineral interests underlying 9,570 net royalty acres. The Partnership funded these acquisitions primarily with borrowings under its revolving credit facility, with portion of the net proceeds from its January and July 2017 offerings of common units and with the issuance of 174,513 common units to a seller in a private placement in May 2017.

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	December 31, 2019	December 31, 2018
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$ 1,316,692	$ 845,228
Not subject to depletion	1,551,767	871,485
Gross oil and natural gas interests	2,868,459	1,716,713
Accumulated depletion and impairment	(326,474)	(248,296)
Oil and natural gas interests, net	2,541,985	1,468,417
Land	5,688	5,688
Property, net of accumulated depletion and impairment	$ 2,547,673	$ 1,474,105
Balance of costs not subject to depletion:		
Incurred in 2019	$ 827,680	
Incurred in 2018	460,977	
Incurred in 2017	263,110	
Total not subject to depletion	$ 1,551,767	

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

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.

There were no impairments recorded for the years ended December 31, 2019, 2018 and 2017. In addition to commodity prices, the Partnership's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test limitations and impairment analysis in future periods.

5. DEBT

	December 31,			
	2019		2018	
	(in thousands)			
5.375 % Senior Notes due 2027	$	500,000	$	—
Revolving credit facility		96,500		411,000
Unamortized debt issuance costs		(2,458)		—
Unamortized discount costs		(7,268)		—
Total long-term debt	$	586,774	$	411,000

2027 Senior Notes

On October 16, 2019, the Partnership completed an offering (the "Notes Offering") of$500.0 million in aggregate principal amount of its 5.375% Senior Notes due 2027 (the "Notes"). The Partnership received net proceeds of approximately $490.0 million from the Notes Offering. The Partnership loaned the gross proceeds to the Operating Company. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility.

The Notes are senior unsecured obligations of the Partnership, initially are guaranteed on a senior unsecured basis by the Operating Company, and will pay interest semi-annually. Neither Diamondback nor the general partner will guarantee the Notes. In the future, each of the Partnership's restricted subsidiaries that either (1) guarantees any of its or a guarantor's other indebtedness or (2) is a domestic restricted subsidiary and is an obligor with respect to any indebtedness under any credit facility will be required to guarantee the Notes.

Intercompany Promissory Note

In connection with and upon closing of the Notes Offering, the Partnership loaned the gross proceeds from the Notes Offering to the Operating Company under the terms of that certain Subordinated Promissory Note, dated as of October 16, 2019, by the Operating Company in favor of the Partnership (the "Intercompany Promissory Note"). The Intercompany Promissory Note requires the Operating Company to repay the underlying loan to the Partnership on the same terms and in the same amounts as the Notes and has the same maturity date, interest rate, change of control repurchase and redemption provisions. The Partnership's right to receive payment under the Intercompany Promissory Note is contractually subordinated to the Operating Company's guarantee of the notes and is structurally subordinated to all of the Operating Company's secured indebtedness (including all borrowings and other obligations under the Operating Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness.

The Operating Company's Revolving Credit Facility

On July 20, 2018, the Partnership, as guarantor, entered into an amended and restated credit agreement with the Operating Company, as borrower, Wells Fargo National Bank ("Wells Fargo"), as administrative agent, and the other lenders. The credit agreement, as amended to the date hereof, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on the Operating Company's oil and natural gas reserves and other factors (the ''borrowing base'') of $775.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. Upon closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million. Effective October 8, 2019, in connection with the commencement of the Notes Offering described above, the Partnership entered into a third amendment to the Operating Company's revolving credit facility, which provided for the waiver of the automatic reduction of the borrowing base that would have otherwise occurred upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or the Partnership from $400.0 million to $1.0 billion.

The Partnership funded the cash portion of the purchase price for the Drop-Down Acquisition through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility. Additionally, in connection with the Partnership's fall redetermination in November 2019, the borrowing base under the Operating Company's revolving credit facility was increased to $775.0 million. As of December 31, 2019, the borrowing base was set at $775.0 million, and the Partnership had $96.5 million of outstanding borrowings and $678.5 million available for future borrowings under its 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 0.75% to 1.75% per annum in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of the loans outstanding in relation to 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 fee 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 of November 1, 2022. The loan is secured by substantially all the assets of the Partnership and the Operating Company.

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 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

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, 2019, the Operating Company was in compliance with all financial 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.

6. RELATED PARTY TRANSACTIONS

Acquisition

On October 1, 2019, the Partnership completed the acquisition from Diamondback of certain mineral and royalty interests across the Midland and Delaware Basins on a transaction valued at $687.4 million. For additional information regarding this acquisition, see Note 3—Acquisitions.

On August 15, 2018, the Partnership acquired from Diamondback mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by Diamondback, for $175.0 million.

Partnership Agreement

The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018 (the "Partnership Agreement"), requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership's behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership's business. The Partnership Agreement does not set a limit on the amount of expenses for which the 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 the Partnership or on the Partnership's behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership. For the year ended December 31, 2019, the General Partner allocated $3.1 million, to the Partnership. For each of the years endedDecember 31, 2018 and 2017, the General Partner allocated $2.5 million, to the Partnership.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and the General Partner entered into an advisory services agreement with Wexford Capital LP ("Wexford") dated as of June 23, 2014 (the "Advisory Services Agreement"), under which Wexford agreed to provide the Partnership and the General Partner with general financial and strategic advisory services related to the Partnership's business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement was terminated on November 12, 2018 with an effective date of December 31, 2018. For the years ended December 31, 2019, 2018 and 2017, the Partnership did not pay any amounts under the Advisory Services Agreement.

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership's 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 the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership's benefit, even though Diamondback had no cash tax expense for that period. For the year ended December 31, 2019, the Partnership did not accrue any state income tax expense. For the year ended December 31, 2018, the Partnership accrued state income tax expense of$0.2 million, for its share of Texas margin tax for which the Partnership's results are included in a combined tax return filed by Diamondback.

Lease Bonus

During the year ended December 31, 2019, Diamondback paid the Partnership $0.3 million in lease bonus payments to extend the term of six leases and $0.2 million in lease bonus payments for four new leases. During the year ended December 31, 2018, Diamondback paid the Partnership $2.5 million in lease bonus payments to extend the term of 13 leases and $0.6 million in lease bonus payments for one new lease. During the year ended December 31, 2017, Diamondback paid the Partnership $0.1 million in lease bonus payments to extend the term of two leases.

7. UNIT–BASED COMPENSATION

In connection with the IPO, the board of directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan ("LTIP"), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. 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. A total of 8,892,918 common units has been reserved for issuance pursuant to the LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The LTIP is administered by the board of directors of the General Partner or a committee thereof.

For the years ended December 31, 2019, 2018 and 2017, the Partnership incurred $1.8 million, $2.8 million and $2.4 million, respectively, of unit–based compensation.

Phantom Units

Under the LTIP, the board of directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting the phantom units entitle the recipient to one common unit of the Partnership for each phantom unit. The Partnership may also grant distribution equivalent rights with respect to Phantom Units. Distribution equivalent rights are rights to receive an amount equal to the cash distributions made during the period a phantom unit is outstanding.

The following table presents the phantom unit activity under the LTIP for the year ended December 31, 2019:

	Phantom Units		Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	125,053	$	23.44
Granted	56,582	$	30.33
Vested	(85,359)	$	23.96
Forfeited	(1,028)	$	42.50
Unvested at December 31, 2019	95,248	$	26.87

The aggregate fair value of phantom units that vested during the year ended December 31, 2019 was $2.0 million. As of December 31, 2019, the unrecognized compensation cost related to unvested phantom units was $1.5 million. Such cost is expected to be recognized over a weighted-average period of 1.01 years.

8. UNITHOLDERS' EQUITY AND PARTNERSHIP DISTRIBUTIONS

The Partnership has general partner and limited partner units. At December 31, 2019, the Partnership had a total of 67,805,707 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 owned by Diamondback, representing approximately 58% of the total Partnership's units outstanding. The Operating Company units and the Partnership's Class B units 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).

The following table summarizes changes in the number of the Partnership's common units:

	Common Units
Balance at December 31, 2018	51,653,956
Common units issued in public offerings	10,925,000
Common units vested and issued under the LTIP	85,359
Units repurchased for tax withholding	(10,732)
Common units issued for acquisition	5,152,124
Balance at December 31, 2019	67,805,707

The following table summarizes changes in the number of the Partnership's Class B units:

	Class B Units
Balance at December 31, 2018	72,418,500
Units issued for the Drop-Down	18,291,446
Balance at December 31, 2019	90,709,946

In March 2019, the Partnership completed an underwritten public offering of10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 54% of the total Partnership units then outstanding. The Partnership received net proceeds from this offering of approximately $340.6 million, after deducting underwriting discounts and commissions and offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the outstanding borrowings under the Operating Company's revolving credit facility and finance acquisitions during the period.

In July 2018, the Partnership completed an underwritten public offering of10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 59% of the total Partnership units then outstanding. The Partnership received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under the revolving credit facility.

In connection with the IPO, the board of directors of the General Partner adopted a policy for the Partnership to distribute all available cash generated on a quarterly basis.

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

Declaration Date	Quarter	Amount per Common Unit	Payment Date	Amount Distributed to Diamondback
				(in thousands)
April 28, 2017	Q1 2017	$ 0.302	May 25, 2017	$ 21,880
July 28, 2017	Q2 2017	$ 0.332	August 24, 2017	$ 24,286
October 16, 2017	Q3 2017	$ 0.337	November 14, 2017	$ 24,652
January 31, 2018	Q4 2017	$ 0.460	February 26, 2018	$ 33,649
April 5, 2018	Q1 2018	$ 0.480	April 27, 2018	$ 35,112
July 27, 2018	Q2 2018	$ 0.600	August 20, 2018	$ 43,901
October 23, 2018	Q3 2018	$ 0.580	November 19, 2018	$ 42,447
January 30, 2019	Q4 2018	$ 0.510	February 25, 2019	$ 37,326
April 25, 2019	Q1 2019	$ 0.380	May 20, 2019	$ 27,817
July 28, 2019	Q2 2019	$ 0.470	August 21, 2019	$ 34,400
October 25, 2019	Q3 2019	$ 0.460	November 15, 2019	$ 33,668

Cash distributions are made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for the Partnership and the Operating Company for each quarter is determined by the board of directors of the Partnership's general partner following the end of such quarter. Available cash for the Operating Company for each quarter will generally equal its Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of the Partnership's general partner deems necessary or appropriate, if any, and the Partnership's available cash will generally equal its Adjusted EBITDA (which will be the proportionate share of the available cash distributed to the Partnership by the Operating Company), less as a result of the Tax Election, cash needed for the payment of income taxes payable by the Partnership, if any.

9. EARNINGS PER UNIT

The net income 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, 2019, 2018 and 2017, 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. Payments made to the Partnership's unitholders are determined in relation to the cash distribution policy described in Note 8—Unitholders' Equity and Partnership Distributions.

Basic net income 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 per common unit gives effect, when applicable, to unvested common units granted under the LTIP.

	Year Ended December 31,		
	2019	2018	2017
	(In thousands, except per unit amounts)		
Net income attributable to the period	$ 46,281	$ 143,958	$ 111,478
Weighted average common units outstanding:			
Basic weighted average common units outstanding	61,744	71,546	104,318
Effect of dilutive securities:			
Potential common units issuable	43	80	65
Diluted weighted average common units outstanding	61,787	71,626	104,383
Net income per common unit, basic	$ 0.75	$ 2.01	$ 1.07
Net income per common unit, diluted	$ 0.75	$ 2.01	$ 1.07

The Partnership had the following units that were excluded from the computation of diluted earnings per unit because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per unit in future periods:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Restricted stock units	—	1	40

10. INCOME TAXES

As discussed further in Note 1—Organization and Basis of Presentation, on March 29, 2018, the Partnership announced that the Board of Directors of the General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. Because the operations of the business continue to be conducted through a pass-through entity, the Operating Company, in which the Partnership and Diamondback have ownership, represents a continuation of the historic pass-through entity for federal income tax purposes. Notwithstanding this federal income tax treatment, the change in the Partnership's tax status is accounted for under financial accounting rules as a change in the Partnership's tax status. This accounting treatment results in the Partnership's financial statements for the year ended December 31, 2018 reflecting an estimated deferred tax benefit attributable to the Partnership succeeding to the tax basis of the Partnership's unitholders in the unitholders' Partnership units as of the effective date of the conversion, and deferred tax benefit related to revision of this estimate for the year ended December 31, 2019.

Subsequent to the Partnership's change in tax status, the Partnership provides for income taxes under the asset and liability method. Deferred tax assets and liabilities are determined based on the difference between the financial statement and tax bases of assets and liabilities, specifically the Partnership's investment in the Operating Company, using enacted tax rates expected to be in effect during the year in which the basis differences reverse. Valuation allowances are established when management determines it is more likely than not that some portion, or all, of the Partnership's deferred tax assets will not be realized.

The Partnership's effective income tax rates were (23.1)% and (38.0)% for the years ended December 31, 2019 and 2018, respectively. 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. Total income tax benefit for the year ended December 31, 2018 differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to (i) net income attributable to the non-controlling interest, (ii) net income attributable to the period prior to the Partnership's change in tax status, and (iii) the impact of deferred taxes recognized as a result of the Partnership's change in tax status.

Prior to May 10, 2018, the effective date of the Partnership's change in income tax status, the Partnership was treated as a pass-through entity for income tax purposes. As a result, the Partnership's partners were responsible for federal income taxes on their share of the Partnership's taxable income.

Viper Energy Partners LP
Notes to Consolidated Financial Statements - (Continued)

The components of the provision for income taxes for the years endedDecember 31, 2019 and 2018 are as follows:

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Current income tax provision (benefit):		
Federal	$ —	$ —
State	—	151
Total current income tax provision	—	151
Deferred income tax provision (benefit):		
Federal	(41,582)	(72,516)
State	—	—
Total deferred income tax provision (benefit)	(41,582)	(72,516)
Total benefit from income taxes	$ (41,582)	$ (72,365)

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

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Income tax expense (benefit) at the federal statutory rate (21%)	$ 37,722	$ 40,008
Impact of net income attributable to the pre-incorporation period	—	(14,279)
Impact of nontaxable noncontrolling interest	(36,735)	(24,973)
State income tax expense (benefit), net of federal tax effect	—	119
Deferred taxes related to change in tax status	(42,424)	(72,787)
Other, net	(145)	(453)
Provision for (benefit from) income taxes	$ (41,582)	$ (72,365)

Viper Energy Partners LP
Notes to Consolidated Financial Statements - (Continued)

The components of the Company's deferred tax assets and liabilities as of December 31, 2019 and 2018 are as follows:

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Deferred tax assets:		
Net operating loss and interest expense carryforwards (indefinite life carryforward)	$ 7,958	$ 2,131
Investment in the Operating Company	134,272	94,468
Other	237	284
Total deferred tax assets	142,467	96,883
Valuation allowance	(1)	—
Net deferred tax assets	142,466	96,883
Deferred tax liabilities:		
Oil and natural gas properties and equipment	—	—
Other	—	—
Total deferred tax liabilities	—	—
Net deferred tax assets (liabilities)	$ 142,466	$ 96,883

As of December 31, 2019 and 2018, the Partnership had net deferred tax assets of approximately $142.5 million and $96.9 million, respectively. Under federal income tax provisions applicable to the Partnership's change in tax status, the Partnership's basis for federal income tax purposes in its interest in the Operating Company consisted primarily of the sum of the Partnership's unitholders' tax bases in their interests in the Partnership on the date of the tax status change. The Partnership prepared its best estimate of the resultant tax basis in the Operating Company for purposes of the Partnership's income tax provision for the period of the change, but information necessary for the partnership to finalize its determination was not available until unitholders' tax basis information was fully reported and the Partnership finalized its federal income tax computations for 2018. Based on such finalized information as of the third quarter 2019, the Partnership revised its estimate of the difference between its tax basis and its basis for financial accounting purposes in the Operating Company on the date of the tax status change, resulting in deferred income tax benefit of $42.4 million included in the Partnership's income tax provision for the year ended December 31, 2019. At December 31, 2019, the Partnership has federal net operating loss carryforwards of approximately $37.9 million which may be carried forward indefinitely to offset future taxable income.

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. At December 31, 2019, management's assessment included consideration of all available positive and negative evidence including the anticipated timing of reversal of deferred tax liabilities and projected future taxable income. As a result of the assessment, a valuation allowance was recorded at December 31, 2019 related to state net operating loss carryforwards not anticipated to be utilized prior to expiration. Management determined that it is more likely than not that the Partnership will realize its remaining deferred tax assets.

The Partnership principally operates in the state of Texas. For the year ended December 31, 2019, the Partnership did not accrue any state income tax expenses. For the year ended December 31, 2018, the Partnership accrued state income tax expense of $0.2 million, for its share of Texas margin tax attributable to the Partnership's results which are included in a combined tax return filed by Diamondback. At December 31, 2019, the Partnership did not have any significant uncertain tax positions requiring recognition in the financial statements. In addition to the 2019 and 2018 tax years, our 2016 and 2017 tax years, periods during which we were organized as a pass-through entity for income tax purposes, remain open to examination by tax authorities.

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.

Viper Energy Partners LP
Notes to Consolidated Financial Statements - (Continued)

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.

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over the limited partnership's operating and financial policies. This interest was acquired during the year ended December 31, 2014 and was accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption.

The Partnership's cost method investment is reported at fair value on a recurring basis. The fair value of the Partnership's investment atDecember 31, 2019, 2018 and 2017 was determined using the quoted market prices for those periods. The investment is a Level 1 classification in the fair value hierarchy.The following table summarizes the changes in fair value of the Partnership's investment:

		(in thousands)
Fair value of investment as of December 31, 2018	$	14,525
Gain on investment		4,832
Fair value of investment as of December 31, 2019	$	19,357

		(in thousands)
Fair value of investment as of December 31, 2017	$	33,851
Impact of adoption of Accounting Standards Update 2016-01		(18,651)
Disposal of shares		(125)
Loss on investment		(550)
Fair value of investment as of December 31, 2018	$	14,525

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

	December 31, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 96,500	$ 96,500	$ 411,000	$ 411,000
5.375% Senior Notes due 2027(1)	$ 490,274	$ 521,100	$ —	$ —

(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 Senior Notes was determined using the December 31, 2019 quoted market price, a Level 1 classification in the fair value hierarchy.

12. COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various legal proceedings, disputes and claims from time to time arising in the 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 believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Partnership's financial condition, cash flows or results of operations. 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 7, 2020, the board of directors of the General Partner approved a cash distribution for thefourth quarter of 2019 of $0.45 per common unit, payable on February 28, 2020, to unitholders of record at the close of business onFebruary 21, 2020.

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,	
	2019	2018
	(In thousands)	
Oil and natural gas interests:		
Proved	$ 1,316,692	$ 845,228
Unproved	1,551,767	871,485
Total oil and natural gas interests	2,868,459	1,716,713
Accumulated depletion and impairment	(326,474)	(248,296)
Net oil and natural gas interests capitalized	$ 2,541,985	$ 1,468,417

Costs incurred in oil and natural gas activities

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

	December 31,		
	2019	2018	2017
	(In thousands)		
Acquisition costs:			
Proved properties	$ 471,464	$ 256,055	$ 55,948
Unproved properties	680,282	356,761	287,131
Total	$ 1,151,746	$ 612,816	$ 343,079

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil, natural gas and natural gas liquids. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to the net operating results of the Partnership's oil, natural gas and natural gas liquids operations.

	December 31,		
	2019	2018	2017
	(In thousands)		
Royalty income	$ 293,811	$ 282,661	$ 160,163
Production and ad valorem taxes	(19,076)	(19,048)	(10,608)
Gathering and transportation	—	—	(789)
Depletion	(78,178)	(58,830)	(40,519)
Income tax expense	(842)	(422)	—
Results of operations from oil, natural gas and natural gas liquids	$ 195,715	$ 204,361	$ 108,247

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2019, 2018 and 2017 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.

Viper Energy Partners LP
Notes to Consolidated Financial Statements - (Continued)

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, 2016	21,344	5,576	27,091
Purchase of reserves in place	2,106	252	5,245
Extensions and discoveries	7,859	1,813	11,106
Revisions of previous estimates	(2,525)	(813)	(3,498)
Production	(2,899)	(533)	(3,549)
As of December 31, 2017	25,885	6,295	36,395
Purchase of reserves in place	5,394	1,163	16,486
Extensions and discoveries	13,858	3,359	13,992
Revisions of previous estimates	1,140	1,108	564
Production	(4,399)	(933)	(5,840)
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
Proved Developed Reserves:			
December 31, 2017	18,788	4,536	29,256
December 31, 2018	29,526	7,965	49,681
December 31, 2019	40,857	14,994	80,737
Proved Undeveloped Reserves:			
December 31, 2017	7,097	1,759	7,139
December 31, 2018	12,352	3,027	11,916
December 31, 2019	13,563	3,570	15,037

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, 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 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.

During the year ended December 31, 2018, the Partnership's extensions and discoveries of 19,549 MBOE resulted primarily from the drilling of 133 new wells and from 138 new proved undeveloped locations added. The Partnership's positive revisions of previous estimated quantities of 2,342 MBOE were primarily due to changes in type curves and realized prices. The purchase of reserves in place of 9,305 MBOE were due to multiple acquisitions with the largest being located in Pecos, Reeves and Howard counties within the Permian Basin as well as an acquisition in the Eagle Ford Shale.

During the year ended December 31, 2017, the Partnership's extensions and discoveries of 11,524 MBOE resulted primarily from the drilling of96 new wells and from 40 new proved undeveloped locations added. The Partnership's negative revisions of previous estimated quantities of3,921 MBOE were primarily due to changes in type curves. The purchase of reserves in place of 3,232 MBOE were due to multiple acquisitions with the largest being located in Pecos, Reeves and Loving counties.

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, 2019, 2018 and 2017:

	December 31,		
	2019	2018	2017
	(In thousands)		
Future cash inflows	$ 3,218,257	$ 2,962,386	$ 1,445,883
Future production taxes	(237,181)	(200,079)	(125,564)
Future income tax expense	(150,373)	(273,643)	(6,932)
Future net cash flows	2,830,703	2,488,664	1,313,387
10% discount to reflect timing of cash flows	(1,512,315)	(1,349,282)	(688,039)
Standardized measure of discounted future net cash flows	$ 1,318,388	$ 1,139,382	$ 625,348

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows:

	December 31,		
	2019	2018	2017
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 52.86	$ 61.46	$ 48.21
Natural gas (per Mcf)	$ 0.51	$ 1.84	$ 2.13
Natural gas liquids (per Bbl)	$ 15.79	$ 25.04	$ 19.15

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

	December 31,		
	2019	2018	2017
	(In thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 1,139,382	$ 625,348	$ 412,581
Purchase of minerals in place	339,814	180,990	54,662
Sales of oil and natural gas, net of production costs	(274,735)	(266,055)	(149,555)
Extensions and discoveries	330,097	423,540	214,479
Net changes in prices and production costs	(301,182)	187,592	99,382
Revisions of previous quantity estimates	(114,409)	52,487	(50,773)
Net changes in income taxes	56,502	(123,804)	(1,129)
Accretion of discount	126,650	62,867	41,477
Net changes in timing of production and other	16,269	(3,583)	4,224
Standardized measure of discounted future net cash flows at the end of the period	$ 1,318,388	$ 1,139,382	$ 625,348

15. QUARTERLY FINANCIAL DATA (Unaudited)

	2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit amounts)			
Operating income	$ 61,590	$ 72,194	$ 71,788	$ 92,711
Income from operations	40,004	49,570	46,555	57,411
Income tax expense (benefit)	(34,608)	180	(7,480)	326
Net income	74,311	47,274	51,097	48,528
Net income attributable to non-controlling interest	40,532	45,009	43,151	46,237
Net income attributable to Viper Energy Partners LP	$ 33,779	$ 2,265	$ 7,946	$ 2,291
Net income attributable to common limited partners per unit:				
Basic	$ 0.61	$ 0.04	$ 0.13	$ 0.03
Diluted	$ 0.61	$ 0.04	$ 0.13	$ 0.03

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit amounts)			
Operating income	$ 62,178	$ 75,263	$ 77,714	$ 73,665
Income from operations	43,703	54,926	54,846	49,512
Income tax expense (benefit)	—	(71,878)	764	(1,251)
Net income	42,896	128,464	50,812	40,705
Net income attributable to non-controlling interest	—	29,060	48,466	41,393
Net income (loss) attributable to Viper Energy Partners LP	$ 42,896	$ 99,404	$ 2,346	$ (688)
Net income attributable to common limited partners per unit:				
Basic	$ 0.38	$ 1.36	$ 0.05	$ (0.01)
Diluted	$ 0.38	$ 1.35	$ 0.05	$ (0.01)

Exhibit 4.1

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of the common units of Viper Energy Partners LP (the "Partnership," "we," "us," and "our"), which is the only class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following summary is not complete. You should refer to the applicable provisions of our certificate of limited partnership, or any supplement or amendment thereto (the "Certificate"), our second amended and restated agreement of limited partnership, as amended (collectively, "our partnership agreement"), and the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), for a complete statement of the terms and rights of the common units. Copies of the Certificate, our second amended and restated partnership agreement and the first amendment to the second amended and restated partnership agreement have been filed with the Securities and Exchange Commission as exhibits 3.1, 3.3 and 3.4, respectively, to our Annual Report on Form 10-K.

Common Units and Class B Units

Our common units and Class B Units represent limited partner interests in us. The holders of our common units and Class B Units are entitled to exercise the rights and privileges provided to limited partners under our partnership agreement, but only holders of our common units are entitled to participate in partnership distributions (except to the extent of the cash preferred distributions equal to 8% per annum payable quarterly on the aggregate capital contributions made to us by Diamondback Energy, Inc. ("Diamondback") and Viper Energy Partners GP, LLC, our general partner. Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

As of February 7, 2020, there were 67,805,707 common units and 90,709,946 Class B Units outstanding.

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that call for the approval of a "unit majority" require the approval of a majority of the outstanding common units and the Class B Units, voting together as a single class.

Diamondback has the ability to ensure passage of, as well as the ability to ensure the defeat of, any amendment which requires a unit majority by virtue of its approximately 58% ownership of our units as of February 7, 2020.

In voting their common units or Class B Units, our general partner and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners. The holders of a majority of the common units and Class B Units (including common units or Class B Units deemed owned by our general partner) represented in person or by proxy shall constitute a quorum at a meeting of such unitholders, unless any such action requires approval by holders of a greater percentage of such units in which case the quorum shall be such greater percentage.

The following is a summary of the vote requirements specified for certain matters under our partnership agreement.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances.
Dissolution of our partnership	Unit majority.
Continuation of our business upon dissolution	Unit majority.
Withdrawal of our general partner	Under most circumstances, the approval of a unit majority, excluding units held by our general partner and its affiliates, if any, is required for the withdrawal of our general partner prior to June 30, 2024 in a manner that would cause a dissolution of our partnership.
Removal of our general partner	Not less than 66 2/3% of the outstanding units, including units held by our general partner and its affiliates.
Transfer of our general partner interest	No approval right.
Transfer of ownership interests in our general partner	No approval right.

Class B Units

Diamondback, either directly or through one of its subsidiaries, holds the same number of Class B Units and the units (the "OpCo Units") in our operating subsidiary, Viper Energy Partners LLC. Each Class B Unit is entitled to one vote on matters that are submitted to our holders of Class B Units for a vote. If at any time Diamondback or any other record holder of one or more Class B Units does not hold an equal number of Class B Units and OpCo Units, we will issue additional Class B Units to such holder or cancel Class B Units held by such holder, as applicable, such that the number of Class B Units held by such holder is equal to the number of OpCo Units held by such holder. The OpCo Units and Class B Units owned by Diamondback are exchangeable from time to time for common units (that is, one OpCo Unit and one Class B Unit, together, are exchangeable for one Common Unit). Our common units and the Class B Units are treated as a single class on all matters submitted for a vote of our unitholders. Additional limited partner interests having special voting rights could also be issued.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units proposed to be sold by our general partner or any of its affiliates (including common units issued upon conversion of Class B Units) or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed.

Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage. Our general partner may postpone any meeting of unitholders one or more times for any reason by giving notice to the unitholders entitled to vote at such meeting. Our general partner may also adjourn any meeting of unitholders one or more times for any reason, including the absence of a quorum, without a vote of the unitholders.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Any notice, demand, request, report or proxy material required or permitted to be given or made to record unitholders under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Amendment of Our Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner has no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in a manner not adverse to us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without such limited partner's consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provision of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;

- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state;

- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our general partner determines to be necessary or appropriate in connection with the creation, authorization or issuance of additional partnership interests or the right to acquire partnership interests;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;

- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- a change in our fiscal year or taxable year and related changes;

- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner, if our general partner determines that those amendments:

- do not adversely affect the limited partners (including any particular class of partnership interests as compared to other classes of partnership interests) in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or

- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and otherwise acts in conformity with the provisions of the partnership agreement, such limited partner's liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital such limited partner is obligated to contribute to us for its common units plus its share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;

- to approve some amendments to our partnership agreement; or

- to take other action under our partnership agreement

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could 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. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

We may have subsidiaries that conduct business in other states or countries in the future. Maintenance of our limited liability as owner of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiaries or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that the action would not result in the loss of limited liability under Delaware law of any limited partner.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as set forth in our partnership agreement. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Jury Trial Waiver

Our Partnership Agreement provides that, to the extent permitted by law, unitholders waive the right to a jury trial of any claim they may have against us arising out of or relating to the common units or our partnership agreement, including any claim under the U.S. federal securities laws. If we opposed a jury trial demand based on the waiver, the court would determine whether the waiver was enforceable under the facts and circumstances of that case in accordance with applicable case law. Unitholders may not be entitled to a jury trial with respect to claims arising under our partnership agreement, which could result in less favorable outcomes to the plaintiffs in any such action.

Anti-Takeover Provisions of our Partnership Agreement

Our partnership agreement contains certain provisions that may be deemed to have an anti-takeover effect and may delay, deter or prevent a tender offer or takeover attempt that a holder of common units might consider in its best interest, including those attempts that might result in a premium over the market price for the common units held by such unitholder.

Loss of Voting Rights Above Certain Threshold

If any person or group other than our General Partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our General Partner or its affiliates and any transferees of that person or group approved by our General Partner or to any person or group who acquires the units with the specific prior approval of our General Partner.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders. However, subject to certain limited exceptions, we will not issue any additional common units unless we contribute the net cash proceeds or other consideration received from the issuance of such additional common units to the Operating Company in exchange for an equivalent number of OpCo Units.

It is likely that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

Our general partner has the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of our general partner and its affiliates, including such interest represented by common units, that existed immediately prior to each issuance.

No Preemptive Rights

The common unitholders do not have preemptive rights under our partnership agreement to acquire additional common units or other partnership interests.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner has no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, we have received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims and irrevocably waives the right to trial by jury.

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 unit, a holder of units is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings.

Limited Call Right

Our partnership agreement provides that at any time our general partner and its affiliates own more than 97% of the limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice; provided, however, our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. The ownership of our general partner and its affiliates (including Diamondback) is currently less than 75% of the outstanding units. Accordingly, the ownership threshold to exercise the call right has been permanently reduced to 80%. The common units and Class B Units are considered limited partner interests of a single class for these provisions. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class over the 20 trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have its limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;

- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed; and

- such other information regarding our affairs as our general partner determines is just and reasonable.

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests, do not have rights to receive information from us or any of the persons we indemnify for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Our partnership agreement limits the rights to information that a limited partner would otherwise have under Delaware law.

Listing

Our common units are listed on the Nasdaq Global Select Market under the symbol “VNOM.” Our Class B Units are not, and will not be, listed on any securities exchange.

Transfer Agent and Registrar

Computershare Trust Company, N.A. serves as registrar and transfer agent for the common units and Class B Units. We pay all fees charged by the transfer agent for transfers of common units and Class B Units, except the following, which must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit or Class B Unit; and
- other similar fees or charges.

There is no charge to our common unitholders for disbursements of our quarterly cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If a successor has not been appointed or has not accepted its appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units and Class B Units

By transfer of our units in accordance with our partnership agreement, each transferee of our common units and Class B Units shall be admitted as a limited partner with respect to the class of units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and

- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements entered into in connection with our formation.

Notwithstanding the foregoing, Class B Units, together with an equal number of OpCo Units, can only be transferred to affiliates of Diamondback.

A transferee will become a substituted limited partner of our partnership for the transferred units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records from time to time as necessary to accurately reflect the transfers.

We may, at our discretion, treat the nominee holder of a common unit or Class B Unit, as applicable, as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units and Class B Units are securities and are transferable according to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner in our partnership for the transferred common units or Class B Units.

Until a common unit or Class B Unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Exhibit 10.8

VIPER ENERGY PARTNERS LP
2014 EQUITY INCENTIVE PLAN

FORM OF PHANTOM UNIT AGREEMENT

THIS PHANTOM UNIT AGREEMENT (this "***Agreement***") is made and entered into by and between Viper Energy Partners GP LLC, a Delaware limited liability company (the "***General Partner***"), and __________ ("you"), effective as of _______ __, 201_ (the "***Date of Grant***").

WHEREAS, Viper Energy Partners LP, a Delaware limited partnership (the "***Partnership***"), acting through the board of directors of the General Partner (the "***Board***"), has adopted the Viper Energy Partners LP 2014 Equity Incentive Plan, as it may be amended from time to time (the "***Plan***"), to, among other things, attract, retain and motivate certain directors, employees and officers of the Partnership, the General Partner and their respective Affiliates (collectively, the "***Partnership Entities***"); and

WHEREAS, the Board has authorized the grant of Phantom Units under the Plan to you as part of your compensation for services provided to the Partnership Entities.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein and for other valuable consideration hereinafter set forth, the parties agree as follows:

1 . Grant of Phantom Units. The General Partner hereby grants to you, effective as of the Date of Grant, the right (the "***Award***") to receive an aggregate of ______ Units (the "***Phantom Units***") on the terms and conditions set forth herein and in the Plan, which Plan is incorporated herein by reference as part of this Agreement. Capitalized terms used in this Agreement but not otherwise defined herein shall have the meanings given to such terms in the Plan, unless the context requires otherwise.

2 . Phantom Units. Each Phantom Unit under the Award is a notional Unit granted under Section 6.4 of the Plan, which upon vesting entitles you to receive, at the time of settlement (which may or may not be coterminous with the vesting schedule of the Award), a Partnership Unit.

3 . Vesting of Phantom Units. Phantom Units shall be deemed "***Nonvested Phantom Units***" unless and until they have become "***Vested Phantom Units***" in accordance with this Section 3.

(a) *Vesting Schedule* . Subject to the other terms and conditions set forth herein, the Phantom Units granted pursuant to this Agreement will become Vested Phantom Units in accordance with the following schedule, provided that you remain in the employ of, or a service provider to, the Partnership Entities until the applicable vesting dates:

Date Phantom Units Become Vested Phantom Units	Number of Phantom Units that Become Vested Phantom Units

(b) *Change of Control*. Notwithstanding the above vesting schedule, upon the occurrence of a Change of Control prior to the date all Phantom Units granted pursuant to this Agreement become Vested Phantom Units, all of Phantom Units subject to this Agreement will immediately become Vested Phantom Units. As used in this Section 3(b), the term "Change of Control" means a Change of Control as defined in the Plan even if such Change of Control does not also constitute a "change in the ownership of a corporation," a "change in the effective control of a corporation," or a "change in the ownership of a substantial portion of a corporation's assets," in each case, within the meaning of § 1.409A-3(i)(5) of the 409A Regulations.

(c) *Termination of Employment*.

(i) General. Except as provided in Section 3(c)(ii) below, notwithstanding anything to the contrary in the foregoing provisions of this Section 3, in the event your employment or service relationship with the Partnership Entities is terminated prior to the date all Phantom Units granted pursuant to this Agreement become Vested Phantom Units, then all of your Nonvested Phantom Units will remain unvested, will become null and void and will be forfeited as of the date of such termination.

(ii) Death and Disability. If your employment or service relationship with the Partnership Entities is terminated due to death or Disability prior to the date all Phantom Units granted pursuant to this Agreement become Vested Phantom Units, then all Phantom Units subject to this Agreement will immediately become Vested Phantom Units as of your employment termination date. As used in this Section 3(c)(ii), "***Disability***" means your inability to substantially perform your duties to the General Partner, the Partnership, or any Affiliate of either by reason of a medically determinable physical or mental impairment that is expected to last for a period of six months or longer or to result in death.

4. Settlement and Payment of Phantom Units.

(a) *Time of Settlement*. Subject to your satisfaction of the applicable tax withholding obligations of Section 6 and the requirements Section 4(b) below, Vested Phantom Units will be settled upon the *earlier* to occur of:

(i) the following schedule:

Date Phantom Units are Settled	Number of Phantom Units that are Settled by Issuance of Units

or

(ii) the date a Change in Control occurs (the earliest occurring of such events, the "***Settlement Date***"). The term "***Change of Control***" means a Change of Control as defined in the Plan.

(b) *Extension of Settlement Date*. Notwithstanding the foregoing provisions of this Section 4, in the event the issuance and delivery of Units on any Settlement Date would violate any applicable Federal, state, local or foreign law (including if, at the time of a proposed settlement, there shall be an effective registration statement registering under the Securities Act of 1933, as amended (the "***Securities Act***"), the issuance of Units upon vesting of Awards under the Plan (the "***Registration Statement***"), and there shall have occurred an event which makes any statement made in the Registration Statement, related prospectus or any document incorporated therein by reference untrue in any material respect or which requires the making of any changes in such Registration Statement, prospectus or other documents so that they will not contain any untrue statement of material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein not misleading), the General Partner may specify another date, during a 30 day period beginning on the date the issuance and delivery of Units for your Vested Phantom Units, or any portion thereof, would first no longer violate an applicable federal, state, local or foreign law, as the Settlement Date for your Vested Phantom Units, or portion thereof, but not later than two and one-half months after the end of the calendar year in which such Award becomes Vested Phantom Units.

(c) *Delivery of Units*. No fractional Units shall be issued with respect to Vested Phantom Units; rather, you will receive a cash payment for such amount as is necessary to eliminate fractional Units and effect the issuance and acceptance of only whole Units. Unless and until a certificate or certificates representing such Units shall have been issued by the Partnership to you or the transfer of such Units shall be entered in the Partnership's ledger or otherwise properly reflected in the Partnership's books and records, you shall not be or have any of the rights or privileges of a unitholder of the Partnership with respect to Units acquirable upon vesting of the Award. The Partnership will not have any obligation to settle the vesting of any Award by transfer of such Units unless and until the General Partner receives the full amount of money as the General Partner may require to meet its withholding obligation under applicable tax laws or regulations and to satisfy the tax withholding obligations of Section 6 hereof.

(d) *Distribution Equivalents*. If the Partnership pays any cash distribution to its outstanding Partnership Unit holders for which the record date occurs after the Date of Grant, the Administrator will pay you as of the distribution payment date an amount equal to the amount of the distribution paid by the Partnership with respect to a single Partnership Unit multiplied by the number of Phantom Units under this Agreement that are unvested as of that record date and that are vested as of that record date but have not been settled under the payment terms of Section 4 ("***Distribution Equivalents***"). Distribution Equivalents will vest and be paid to the Participant on the distribution payment date (but not later than two and one-half months after the end of the year that includes the distribution record date) if Participant is in the employ of, or a service provider to, the Partnership Entities on the distribution record date declared by the Partnership.

5. **Transferability**. This Agreement and the Phantom Units granted hereunder will not be transferrable or assignable by you other than by will or the laws of descent and distribution, except to the extent approved by the Administrator in accordance with the terms of the Plan. Notwithstanding the foregoing, if you are serving as a Designated Director of the General Partner, you may enter into a transfer agreement that transfers this Award and requires issuance of the Units in settlement of the Vested Phantom Units to an entity, including without limitation a private equity or other investment fund that is an investor in the Partnership (an "***Investor***"), subject to compliance with all applicable securities laws. A "***Designated Director***" is a Director of the General Partner who is an employee or partner of an Investor and who is treated as serving on behalf of such Investor because the services provided to the General Partner depend upon the exercise of expertise and are similar to those that are performed for the Investor and the Investor has established a policy that provides that the Investor is entitled to the benefit of any compensation provided for services provided as a Director of any portfolio company.

6. **Payment of Taxes**. To the extent that the settlement of this Award or the disposition of Units acquired by vesting of this Award results in compensation income or wages to you for federal, state or local tax purposes that are subject to withholding requirements, you shall deliver to the General Partner at the time of such settlement or disposition such amount of money as the General Partner may require to meet its withholding obligation under applicable tax laws or regulations. You may satisfy such tax withholding obligation (i) in cash (including by certified check, bank draft or money order, or wire transfer of immediately available funds); or (ii) in the Administrator's discretion and on such terms as the Administrator approves: (A) by delivering or constructively tendering by means of attestation whereby you identify for delivery specific duly endorsed Units having a Fair Market Value equal to the aggregate withholding obligation (provided that any Units used for this purpose must have been held by you for such minimum period of time, if any, as may be established from time to time by the Administrator), (B) by notice of net issuance including a statement directing the Partnership to retain from transfer the number of Units with a Fair Market Value equal to the aggregate withholding obligation, in which case the Award will be surrendered and cancelled with respect to the number of Units retained by the Partnership, or (C) to the extent permissible under applicable law, through delivery of irrevocable instructions to a broker to sell a sufficient number of the Units being settled to cover the aggregate withholding obligation and delivery to the General Partner on behalf of the Partnership (on the same day that the Units issuable upon vesting are delivered) of the amount of sale proceeds required to pay the aggregate withholding obligation; or (iii) any combination of the foregoing. In the event the Administrator subsequently determines that the amount paid or withheld as payment of any tax withholding obligations is insufficient to discharge the tax withholding obligation, you will be required to pay to the General Partner, immediately upon the Administrator's request, the amount of that deficiency. No Units will be transferred to you pursuant to Section 4(c) until the full amount of any required tax withholding obligation has been received by the General Partner.

7. **Nonqualified Deferred Compensation Rules**. The intent of the parties is that the Award and related rights under this Agreement will be exempt under Section 409A of the Code and the 409A Regulations as a short-term deferral and, accordingly, to the maximum extent permitted, this Agreement shall be interpreted to be in compliance therewith. In the event the Award is subject to Section 409A, the General Partner, the Partnership and you shall take commercially reasonable efforts to reform or amend any provision hereof to the extent it is reasonably determined that such provision would or could reasonably be expected to cause you to incur any additional tax or interest under Section 409A or the 409A Regulations to try to comply with the requirements of Section 409A and the 409A Regulations through good faith modifications, in any case, to the minimum extent reasonably appropriate to conform with such requirements; provided, that any such modification shall not increase the cost or liability to the General Partner or the Partnership. To the extent that any provision hereof is modified in order to comply with Section 409A and the 409A Regulations, such modification shall be made in good faith and shall, to the maximum extent reasonably possible, maintain the original intent and economic benefit to the General Partner, the Partnership and you of the applicable provision without violating the provisions of Section 409A and the 409A Regulations. Notwithstanding the foregoing provisions of this Section 7, you are responsible for any and all taxes (including any taxes imposed under Section 409A of the Code) associated with the grant or vesting of, or otherwise with respect to, the Award and matters related thereto. For purposes of Section 409A of the Code, each payment or amount due under this Agreement shall be considered a separate payment.

8. Miscellaneous.

(a) *No Right to Continued Service*. This Award shall not be construed to confer upon you any right to continue as an employee of or other service provider to the Partnership Entities. Any question as to whether and when there has been a termination of employment or service shall be determined by the Administrator and its determination shall be final and binding. Records of the Partnership Entities regarding your period of service, termination of service, leaves of absence and other matters shall be conclusive for all purposes hereunder, unless determined by the Administrator to be incorrect.

(b) *Administration*. This Agreement shall at all times be subject to the terms and conditions of the Plan. The Administrator shall have sole and complete discretion with respect to all matters reserved to it by the Plan and decisions of the Administrator or a majority of the Committee designated as Administrator with respect thereto and to this Agreement shall be final and binding upon you and the Partnership Entities. In the event of any conflict between the terms and conditions of this Agreement and the Plan, the provisions of the Plan shall control.

(c) *No Liability for Good Faith Determinations*. The Partnership Entities, the members of the Board and the Administrator, shall not be liable for any act, omission or determination taken or made in good faith with respect to this Agreement or the Award granted hereunder.

(d) *No Guarantee of Interests*. The Partnership Entities the members of the Board and the Administrator, do not guarantee the Units from loss or depreciation.

(e) *Severability*. If any provision of this Agreement is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions hereof, but such provision shall be fully severable and this Agreement shall be construed and enforced as if the illegal or invalid provision had never been included herein.

(f) *Binding Effect*. This Agreement shall be binding upon you, your legal representatives, heirs, legatees and distributees, and upon the Partnership Entities and their successors and assigns.

(g) *Construction*. The titles and headings of sections are included for convenience of reference only and are not to be considered in construction of the provisions hereof. Words used in the masculine shall apply to the feminine where applicable and whenever the context of this Agreement dictates, the plural shall be read as the singular and the singular as the plural.

(h) *Governing Law*. All questions arising with respect to the provisions of this Agreement shall be determined by application of the laws of the State of Delaware without regard to choice of law principles thereunder, except to the extent Delaware law is preempted by federal law.

(i) *Amendment*. This Agreement may be amended by the Administrator; provided, however, that, unless otherwise provided in the Plan, no such amendment may materially reduce your rights or benefits inherent in this Agreement prior to such amendment without your express written consent. For the avoidance of doubt, a cancellation of all or a part of this Award where you receive a payment equal in value to the Fair Market Value of the vested Award will not constitute an impairment of your rights that requires your consent.

(j) *Furnish Information*. You agree to furnish to the General Partner or the Partnership all information requested by them to enable the Partnership Entities to comply with any reporting or other requirements imposed upon them by or under any applicable statute or regulation.

(k) *Execution of Receipts and Releases*. Any payment of cash or any issuance or transfer of Units or other property to you, or to your legal representative, heir, legatee or distributee, shall, to the extent thereof, be in full satisfaction of all claims of such persons hereunder. The Administrator may require you or your legal representative, heir, legatee or distributee, as a condition precedent to such payment or issuance, to execute a release and receipt therefor in such form as it shall determine.

(l) *Consent to Electronic Delivery; Electronic Signature*. In lieu of receiving documents in paper format, you agree, to the fullest extent permitted by law, to accept electronic delivery of any documents that the Partnership Entities may be required to deliver (including, without limitation, prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the Partnership. Electronic delivery may be via an electronic mail system of the Partnership Entities or by reference to a location on a Partnership intranet to which you have access. You hereby consent to any and all procedures the Partnership Entities have established or may establish for an electronic signature system for delivery and acceptance of any such documents that the Partnership Entities may be required to deliver, and agree that your electronic signature is the same as, and shall have the same force and effect as, your manual signature.

[Signatures appear on following page]

IN WITNESS WHEREOF, the General Partner has caused this Agreement to be executed by its duly authorized agent effective as of the date first written above.

VIPER ENERGY PARTNERS GP LLC

Dated: ____________________ By: ________________________________

Travis D. Stice, Chief Executive Officer

By your signature below and the signature of the General Partner's representative above, you and the General Partner agree to be bound by all of the terms and conditions of this Phantom Unit Agreement and the Plan (incorporated herein by this reference as if set forth in full in this document). By executing this Phantom Unit Agreement, you hereby irrevocably elect to accept the Phantom Unit rights granted pursuant to this Phantom Unit Agreement and to receive the Award to purchase Units of Viper Energy Partners LP designated above subject to the terms of the Plan and this Phantom Unit Agreement.

AWARD RECIPIENT

Dated: ____________________ ________________________________

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 18, 2020, 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, 2019. 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. 333-226411, effective July 30, 2018) and Form S-8 (File No. 333-196971, effective June 23, 2014).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 18, 2020

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 10, 2020 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, 2019. 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-8 (File No. 333-196971, effective June 23, 2014) and Form S-3 ASR (File No. 333-226411, effective July 30, 2018).

/s/ Ryder Scott Company, L.P.

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

Houston, Texas

February 18, 2020

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 18, 2020

/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 18, 2020

/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 18, 2020	/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 18, 2020	/s/ Teresa L. Dick
		Teresa L. Dick Chief Financial Officer Viper Energy Partners GP LLC (as general partner of Viper Energy Partners LP)

VIPER ENERGY PARTNERS, LP

Estimated

Future Reserves and Income

Attributable to Certain

Royalty Interests

SEC Parameters

As of

December 31, 2019

\s\ Val Rick Robinson

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

[SEAL]

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

January 10, 2020

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, 2019. 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 January 7, 2020 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, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 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, 2019

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate – Mbbl	40,857	13,563	54,420
Plant Products – Mbbl	14,994	3,570	18,564
Gas – MMcf	80,737	15,037	95,774
MBOE	69,307	19,639	88,946
Income Data ($M)			
Future Gross Revenue	$2,317,872	$741,187	$3,059,059
Deductions	58,807	19,176	77,983
Future Net Income (FNI)	$2,259,065	$722,011	$2,981,076
Discounted FNI @ 10%	$1,036,004	$353,004	$1,389,008

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 98 percent and gas reserves account for the remaining 2 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.

	Discounted Future Net Income ($M) As of December 31, 2019
Discount Rate Percent	Total Proved
5	$1,850,832
15	$1,138,082
20	$977,996
30	$781,477

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 to 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 85 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, 2019 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 15 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, 2019. 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 areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.69/bbl	$52.86/bbl
	NGLs	WTI Cushing	$55.69/bbl	$15.79/bbl
	Gas	Henry Hub	$2.58/MMBTU	$0.51/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, 2019. 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, 2019, 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, 2019 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.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

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

[SEAL]

VRR (GR)/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 2019 continuing education hours, Mr. Robinson attended 32 hours of formalized training including the 2019 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 16 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 February 19, 2007.

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.