Viper Energy Partners LP
Form 10-K
February 20, 2015
Table of Contents

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

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR
o 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)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	46-5001985 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices)	79701 (Zip Code)

(432) 221-7400
(Registrant Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partner Interests	The NASDAQ Stock Market LLC (Global Market)

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

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

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 ý

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 ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large Accelerated Filer	o	Accelerated Filer	o
Non-Accelerated Filer	ý	Smaller Reporting Company	o

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

The aggregate market value of the common units held by non-affiliates was approximately $177.5 million on June 30, 2014, 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 Market on such date. As of February 19, 2015, 79,708,888 common limited partner units of the registrant were outstanding.

Documents Incorporated By Reference: None

VIPER ENERGY PARTNERS LP
TABLE OF CONTENTS

GLOSSARY OF TERMS

The following includes a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K ("Annual 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 Annual Report in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Bbls per day.

BOE. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BOE/d. BOE per day.

British Thermal Unit. 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 of a primarily natural gas reserve.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

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. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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.

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.

Estimated Ultimate Recovery or EUR. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory prospects. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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.
Inception. September 18, 2013.
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.
Mcf/d. Mcf per day.
Mineral interests. The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu. Million British Thermal Units.
MMcf. Million cubic feet of natural gas.
Net acres or net wells. The sum of the fractional working interest owned in gross acres.
Net revenue interest. An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
NYMEX. New York Mercantile Exchange.
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.
PDP. Proved developed producing.
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.
SEC. Securities and Exchange Commission.
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. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.
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 commercial 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.

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 of 1933, as amended (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended (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 ide 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:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- 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;
- 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;
- 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 Annual Report. 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 Annual 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.

Table of Contents

PART I

References in this Annual Report to "Viper Energy Partners LP Predecessor," "our predecessor," "we," "our," "us" or like terms when used for periods prior to June 17, 2014 refer to Viper Energy Partners LLC, which Diamondback Energy, Inc. (NasdaqGS: FANG) contributed to Viper Energy Partners LP in connection with Viper Energy Partners LP's initial public offering on June 23, 2014. When used for periods on and after June 17, 2014, "we," "our," "us" or like terms refer to Viper Energy Partners LP and its subsidiaries. Except where expressly noted otherwise, references in this Annual Report to "Diamondback" refer to Diamondback Energy, Inc. and its subsidiaries other than Viper Energy Partners LP and its subsidiaries. References in this Annual Report to "our general partner" refer to Viper Energy Partners GP LLC, a wholly owned subsidiary of Diamondback Energy, Inc. References in this Annual Report to "Wexford" refer to Wexford Capital LP, which is a Greenwich, Connecticut-based SEC-registered investment advisor.

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Overview

We are a Delaware limited partnership formed by Diamondback on February 27, 2014 to own, acquire and exploit oil and natural gas properties in North America.

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, which it acquired in September 2013 from a third party for cash, to us upon the closing of our initial public offering ("IPO") of common units 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. However, because of the nature of the rock in many of the potentially productive zones, historically it was not economic to exploit these zones. As a result, exploration and development was limited until higher oil prices and more advanced completion techniques, including hydraulic fracturing, changed the economics of drilling and development of these zones and greatly increased the oil and natural gas industry's interest in the Permian Basin. Oil production in the Permian Basin has grown from 850,000 barrels per day in 2008 to 1.8 million barrels per day in 2014. Based on public statements made by a number of publicly traded oil and natural gas companies, and the successful horizontal well results of the industry, we believe that drilling activity in the Permian Basin is likely to continue to grow at least for several more years.

Our Properties

Our initial assets consisted of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. Diamondback acquired the mineral interests for $440 million on September 19, 2013 and contributed them to us upon the closing of our IPO. As of December 31, 2014 our total acreage position in the Permian Basin was 24,528 gross (15,948 net) acres. Diamondback is the operator of approximately 43% of this acreage. As of December 31, 2014, there were 241 vertical wells and 55 horizontal wells producing on this acreage, and average net production was approximately 4,337 net BOE/d during December 2014. In addition, there were seven vertical wells and 18 horizontal wells in various stages of completion. For the year ended December 31, 2014 and the period from inception to December 31, 2013, royalty revenue generated from these mineral interests was $77.8 million and $15.0 million, respectively.

The estimated proved oil and natural gas reserves of our assets, as of December 31, 2014, were 18,510 MBOE based on a reserve report prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers. Of these reserves, approximately 53% were classified as PDP reserves. PUD reserves included in this estimate were from 53 vertical gross well locations on 40-acre spacing and 50 gross horizontal well locations. As of December 31, 2014, our proved reserves were approximately 69% oil, 14% natural gas liquids and 17% natural gas.

Our mineral interests entitle us to receive a 15.7% royalty interest on an acreage weighted basis on all production from our approximately 24,528 gross acres with no additional future capital or operating expense required. The actual royalty percentage varies by lease and ranges from 6.3% 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. On an acreage weighted basis, our average royalty percentage is 20.9% on the portion of the acreage that Diamondback operates and is 13.1% on the portion of

1

the acreage operated by others. In just the Midland County portion of the acreage operated by others, the average royalty percentage is 21.9%. As additional acreage is developed, we anticipate that the average royalty percentage on a production basis will change and likely will increase as more of the higher royalty acreage is developed.

Based on Diamondback's evaluation of applicable geologic and engineering data as of December 31, 2014, with respect to the approximate 43% of our mineral interests for which it is the operator, Diamondback had identified 308 potential horizontal drilling locations in multiple horizons on our acreage. As of such date, Diamondback also had 59 identified potential vertical drilling locations on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. 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 Spanish Trail operated by others has very similar production characteristics to the portion operated by Diamondback. RSP Permian, Inc. ("RSP Permian") is the operator of a majority of our properties in Spanish Trail that are not operated by Diamondback. Diamondback has advised us that it believes it has a good relationship with RSP Permian and that it shares, on occasion, drilling and production information with RSP Permian to encourage further development of our properties. Additionally, Diamondback has participated with RSP Permian in the drilling and completion of five horizontal wells on shared acreage subject to our mineral interests.

In addition to our mineral interests, we own a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests. The equity interest is so minor that we have no influence over partnership operating and financial policies and is accounted for under the cost method.

Our Relationship with Diamondback

Diamondback owns and controls our general partner and, as of December 31, 2014, owned approximately 88.4% of our outstanding common units. 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 we believe 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 nor our subsidiary 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 Annual Report.

Prior to October 11, 2012, Wexford beneficially owned 100% of the equity interests in Diamondback. Upon completion of Diamondback's initial public offering, Wexford beneficially owned approximately 44.4% of its common stock. As a result of the issuance of additional shares of common stock by Diamondback and sales of its common stock by affiliates of Wexford, as of December 31, 2014, Wexford beneficially owned approximately 7.7% of the common stock of Diamondback.

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 distributions. Our initial assets consisted of mineral interests in the Permian Basin in West Texas. In the second half of 2014, we acquired mineral interests in the Midland and Delaware Basins. We expect the production from our mineral interest will increase as Diamondback and our other operators continue to actively drill and develop our acreage. We expect to capitalize on this development, cost-free to us, and believe the resulting increase in production will contribute to increased aggregate royalty payments will enable us to grow our distributions.

- 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 intend 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 long histories 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. We may have additional opportunities to acquire mineral or other interests in producing oil and natural gas properties directly from Diamondback or third parties from time to time in the future. 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.

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. All 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. The majority of our current properties are well positioned in the core of the Wolfberry play. Production on our properties for the year ended December 31, 2014 was approximately 77% oil, 13% natural gas liquids and 10% natural gas. As of December 31, 2014, our estimated net proved reserves were comprised of approximately 69% oil and 14% natural gas liquids, which allows us to benefit from the currently more favorable pricing of oil and natural gas liquids as compared to natural gas. We believe that we will have a strong, growing production profile driven by Diamondback, a growth-oriented operator.
- Multi-year drilling inventory in one of North America's leading oil resource plays. We expect our reserves and cash available for distributions to grow organically as our operators continue to drill new wells on our acreage. Diamondback, as the operator of approximately 43% of our properties, 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. As of December 31, 2014, with respect to the approximate 43% of our properties operated by it, Diamondback has identified 308 potential horizontal locations on the acreage operated by Diamondback based on Diamondback's initial results and those of the other operators in the area to date, combined with its interpretations of various geologic and engineering data. These locations exist across most of the acreage and in multiple horizons. Of these 308 potential locations, 119 are in the Wolfcamp B or Lower Spraberry horizons, with the remaining locations in the Wolfcamp A, Clearfork, Middle Spraberry or Cline (or Wolfcamp D) horizons. Diamondback's current potential horizontal location count is based on 660-foot spacing between wells in the Wolfcamp B and Lower Spraberry horizons in Midland County, 880-foot spacing in the Middle Spraberry horizon and 1,320-foot spacing in other horizons. The ultimate inter-well spacing may be less than these amounts, which would result in a higher location count. Based on horizontal wells drilled to date, Ryder Scott assigned reserves to PUD locations ranging from 378 MBOE for 5,000-foot laterals in the Middle Spraberry to 1,316 MBOE for 10,000-foot laterals in the Lower Spraberry. When normalized to 7,500-foot laterals, Ryder Scott assigned PUD values of 638 MBOE for the Wolfcamp B horizon, 993 MBOE for the Lower Spraberry horizon and 567 MBOE for the Middle Spraberry horizon. These PUD locations, as assigned by Ryder Scott, are for direct offsets to producing wells. Based on various geologic

and engineering parameters, we believe that the estimates assigned to these PUD locations are reasonable estimates for PUD locations on the remaining portion of our acreage. Additionally, we believe that there is similar potential for horizontal development on the portion of our acreage for which Diamondback is not the operator. Diamondback had 59 identified potential vertical drilling locations based on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. The gross EURs from the future PUD vertical wells included in our reserve report on 40-acre spacing, as estimated by Ryder

Scott as of December 31, 2014, range from 101 MBOE per well, consisting of 77 MBbls of oil and 142 MMcf of natural gas, to 145 MBOE per well, consisting of 111 MBbls of oil and 206 MMcf of natural gas, with an average EUR per well of 134 MBOE, consisting of 102 MBbls of oil and 193 MMcf of natural gas. Diamondback has advised us that it currently anticipates a reduction of approximately 20% in EURs from vertical wells drilled on 20-acre spacing.

Oil and Natural Gas Data

Proved Reserves

SEC Rule-Making Activity

Our reserve estimate disclosures are made in accordance with the Securities and Exchange Commission ("SEC") final rules on "Modernization of Oil and Gas Reporting," released in December 2008. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required, unless contractual arrangements designate the price to be used. These rules also include the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- The ability to book proven undeveloped reserves, subject to certain exceptions, only if they relate to wells scheduled to be drilled within five years of the date of booking, as well as the requirement to write down proved undeveloped reserves if the associated wells are not drilled within the required five-year timeframe.
- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2014 and 2013 were prepared by Ryder Scott. A reserve audit is not the same as a financial audit and is less vigorous in nature than an independent reserve report where the independent reserve engineer determines the reserves on its own.

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, 2014 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

4

90% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 10% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

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

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. Our Vice President—Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Vice President—Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 26 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 Vice President—Reservoir Engineering of our general partner or under his direct supervision;
- review by the 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 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, 2014 and 2013 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, 2014		2013	
Estimated proved developed reserves:				
Oil (Bbls)	6,951,892		3,692,207	
Natural gas (Mcf)	10,377,401		6,280,409	
Natural gas liquids (Bbls)	1,470,966		609,303	
Total (BOE)	10,152,425		5,348,245	
Estimated proved undeveloped reserves:				
Oil (Bbls)	5,878,402		3,525,873	
Natural gas (Mcf)	8,616,759		4,981,176	
Natural gas liquids (Bbls)	1,042,742		565,820	
Total (BOE)	8,357,271		4,921,889	
Estimated Net Proved Reserves:				
Oil (Bbls)	12,830,294		7,218,080	
Natural gas (Mcf)	18,994,160		11,261,585	
Natural gas liquids (Bbls)	2,513,708		1,175,123	
Total (BOE)(1)	18,509,696		10,270,135	
Percent proved developed	54.8	%	52.1	%

(1) Estimates of reserves as of December 31, 2014 and 2013 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, 2014 and 2013, 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, 2014, our proved developed reserves totaled 6,952 MBbls of oil, 10,377 MMcf of natural gas and 1,471 MBbls of natural gas liquids, for a total of 10,152 MBOE. Of the total proved developed reserves, 97% were producing and the remaining 3% were from wells that had been stimulated but were not yet producing hydrocarbons. Producing reserves were from 241 vertical wells and 55 horizontal wells, of which Diamondback was the operator of 122 vertical wells and 44 horizontal wells and RSP Permian was the operator of 95 vertical wells and nine horizontal wells. The remaining 26 vertical wells were operated by various other companies. Of the total 296 producing wells, Diamondback had a working interest in 191 wells. Non-producing reserves were from one vertical well and two horizontal wells in various stages of completion and one well that was behind pipe recompletion.

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, 2014, our proved undeveloped reserves totaled 5,878 MBbls of oil, 8,617 MMcf of natural gas and 1,043 MBbls of natural gas liquids, for a total of 8,357 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Our undeveloped reserves were from 53 vertical wells and 50 horizontal wells, of which Diamondback was the operator of 23 vertical wells and 31 horizontal wells and RSP

Permian was the operator of 30 vertical wells and 17 horizontal wells, with the remaining two horizontal wells operated by others. Diamondback also had a non-operated working interest in five of the vertical wells and nine horizontal wells that were operated by RSP Permian. Of the horizontal locations, 28 were Wolfcamp B wells, 16 were Lower Spraberry wells, four were Middle Spraberry wells and two were 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, 2014, approximately 1.6% of our total proved reserves were classified as proved developed non-producing.

Changes in PUDs that occurred during 2014 were primarily due to:

- additions of 5,713 MBOE, primarily from 37 horizontal well locations, 21 in the Wolfcamp interval and 16 in Spraberry intervals, attributable to extensions resulting from strategic drilling of wells to delineate our acreage position;
- downgrade of PUDs into probable category of 670 MBOE for 29 vertical wells that are not anticipated to be drilled under the five-year rule due to a shift in focus from vertical development to horizontal development;
- the conversion of approximately 1,832 MBOE attributable to PUDs into proved developed reserves; and
- positive revisions of approximately 224 MBOE in PUDs primarily due to increased Lower Spraberry reserves.

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 in West Texas, and certain price and cost information for each of the periods indicated:

	Year Ended December 31, 2014	Period from Inception to December 31, 2013
Production Data:		
Oil (Bbls)	856,541	150,815
Natural gas (Mcf)	648,808	108,264
Natural gas liquids (Bbl)	144,074	19,971
Combined volumes (BOE)	1,108,750	188,830
Daily combined volumes (BOE/d)	3,038	1,798
Average Prices:		
Oil (per Bbl)	$82.98	$92.07
Natural gas (per Mcf)	4.18	3.67
Natural gas liquids (per Bbl)	27.59	35.30
Combined (per BOE)	70.14	79.37

Productive Wells

As of December 31, 2014, our operators owned a working interest in 296 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. During 2014, we received division orders or first payments for 64 new wells completed on our acreage.

Acreage

The following table sets forth information as of December 31, 2014 relating to the gross and net acreage of our mineral interests:

Basin	Gross Acreage	Net Acreage
Permian	24,528	15,948

7

Our net interest in production from our mineral interests is based on lease royalty terms which vary from property to property. Our interest in these properties is perpetual in nature.

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 and 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 protection of the environment or occupational health and safety. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency (“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 sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing earthen 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. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. 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 adversely affect our business and prospects.

Waste Handling

The Resource Conservation and Recovery Act, as amended (“RCRA”), 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 RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure our unitholders that the EPA or state or local governments will not 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.” 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 (“CERCLA”), also known as the “Superfund” law, and analogous state laws, generally imposes strict and joint and several 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” may be subject to strict and joint and several liability 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 (“SDWA”), the Oil Pollution Act (“OPA”), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. 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. 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. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. 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 October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for shale gas in early 2015. 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 OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability 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.

Noncompliance with the Clean Water Act or OPA 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." 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 December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including rules which regulate emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

The EPA has continued to adopt GHG regulations applicable to other industries, such as the September 2013 proposed GHG rule that, if finalized, would set new source performance standards for new coal-fired and natural-gas fired power plants, which could have an adverse effect on our financial condition and results of operations. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. 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 has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados 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 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, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal SDWA regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. Also, the EPA is updating the chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. Moreover, the EPA announced in October 2011 that it was launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards in early 2015 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA approved 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 ("NSP standards") to address emissions of sulfur dioxide and volatile organic compounds, ("VOCs") 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 rule seeks to achieve a 95% reduction in VOCs 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. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. Also, on December 19, 2014, the EPA released final updates and clarifications to the NSP standards. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior

(“DOI”) published a revised proposed rule on May 24, 2013 that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending. In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources, with results of the study anticipated to be available in March 2015. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission ("RRC") has adopted rules and regulations implementing this legislation that apply to all wells for which the RRC issues an initial drilling permit after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure on an internet website and also file the list of chemicals with the RRC 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 RRC. Additionally, on October 28, 2014, the RRC 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 also clarify the RRC'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 disposal well rule amendments became effective November 17, 2014. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, 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 legislative 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 or state legislation 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 the Federal Energy Regulatory Commission (“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 abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers 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 (“NGA”) 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 our operators 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 must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. 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 the market value of oil production and a 7.5% severance tax on the market value of 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. We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford provides general financial and strategic advisory services to us and our general partner.

As of December 31, 2014, Diamondback had 114 full-time employees. None of Diamondback's employees are represented by labor unions or covered by any collective bargaining agreements. Diamondback also hires independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist its full time employees. 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 Annual Report.

14

Facilities

Diamondback leases office space for our principal executive offices in Midland, Texas. We believe that these facilities are adequate for our current operations.

Availability of Company Reports

Our annual report 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.

Table of Contents

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 prices that our operators realize from the sale of oil and natural gas. 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.

Our business is difficult to evaluate because we have a limited operating history.

Viper Energy Partners LP was formed in February 2014. In September 2013, our predecessor acquired the mineral interests contributed to us upon the consummation of the IPO. Moreover, we do not have historical financial statements with respect to the mineral interests for periods prior to their acquisition by Diamondback in September 2013. As a result, there is only limited historical financial and operating information available upon which to base an evaluation of our performance.

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 will 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.

Table of Contents

The volatility of oil and natural gas 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;
- 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;
- the price and availability of alternative fuels; 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. For example, during the past five years from December 31, 2014, the posted price for West Texas Intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $53.45 per barrel, or Bbl, in December 2014 to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per million British thermal units, or MMBtu, in April 2012 to a high of $8.15 per MMBtu in February 2014. During 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On December 31, 2014, the West Texas Intermediate posted price for crude oil was $53.45 per Bbl and the Henry Hub spot market price of natural gas was $3.14 per MMBtu. Over the past several months, oil prices have declined from over $105.00 per Bbl in June 2014 to below $45.00 per Bbl in January 2015 due in large part to increasing supplies and weakening demand growth. If the prices of oil and natural gas continue at current levels and are not offset by increased production, or further decline, our operations, financial condition, cash available for distribution and level of expenditures for the development of 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 our credit agreement, 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

17

Table of Contents

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.

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

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, and we do not intend to enter into such arrangements in the future. As a result, 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 decreases significantly, our business, results of operation and cash available for distribution may be materially adversely affected.

We depend on two operators for substantially all 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 the year ended December 31, 2014, we received approximately 75% and 22% of our royalty revenue from Diamondback and RSP Permian, respectively. The failure of Diamondback or RSP Permian 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. Further, none of the operators of our properties are obligated to undertake any development activities, so any development and production activities will be subject to their reasonable discretion. Either or both of Diamondback and RSP Permian could determine to drill and complete fewer wells on our acreage than is currently expected. The 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:

- 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 45.2% of our total estimated proved reserves as of December 31, 2014 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 report of our independent petroleum engineer 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 decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped

Table of Contents

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 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.

All of our producing properties are 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 properties, they 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, results of operations and cash available for distribution.

In addition to the geographic concentration of our producing properties described above, as of December 31, 2014, all of our proved reserves were attributable to the Wolfberry play. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause our operators to permanently or temporarily shut-in all 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 initially 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.

Table of Contents

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, which could result in unforeseen operating difficulties. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

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, 2014, Diamondback, which is the operator for 43% of the acreage associated with our properties, drilled a total of 57 gross wells and participated in two additional gross non-operated wells, of which 42 wells were completed as producing wells and 17 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 impairment of asset value.
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. 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

Table of Contents

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 $24.95 and $27.53 for the year ended December 31, 2014 and for the period from inception through December 31, 2013, 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. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2014 and for the period from inception through December 31, 2013. We may, however, experience ceiling test write downs in the future. 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.”

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, 2014 and 2013, 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 are ultimately recovered being different from our reserve estimates.

The estimates of reserves as of December 31, 2014 and 2013 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 year ended December 31, 2014 and 2013, respectively, in accordance with the SEC guidelines applicable to reserve estimates for such period. 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.

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 our operators pursue their drilling programs. Moreover, we may be required to write down our proved undeveloped reserves if those wells are not drilled within the required five-year timeframe.

Declining 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, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a 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 further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids

Table of Contents

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 of our general partner, Travis D. Stice, could disrupt our business. Diamondback has employment agreements with Travis D. Stice and Teresa L. Dick, the Chief Financial Officer 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. 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.

Our credit agreement has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

The operating and financial restrictions and covenants in our credit agreement and any future financing agreements may restrict our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to pay distributions to our unitholders. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." Our 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. If we violate any provisions of our credit agreement that are not cured or waived within the appropriate time periods provided in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions to our unitholders will be inhibited and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit agreement are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit agreement, the lenders could seek to foreclose on our assets.

Our credit agreement allows us to borrow in an amount up to the borrowing base, which is based on our oil and natural gas reserves and other factors as determined semi-annually by our lenders in their sole discretion. A further

decline in commodity prices could result in a redetermination that lowers our borrowing base at that time and, in such case, we could be required to repay any indebtedness outstanding in excess of the borrowing base. If we are unable to repay any borrowings in excess of a decreased borrowing base, we would be in default and no longer able to make any distributions to our unitholders.
Loss of our information and computer systems could adversely affect our business.

Table of Contents

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 Operators and Other Working Interest Owners

The following risks describe risks that may directly 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. In addition, any operators of our properties, including our current operators, 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. 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 the current operators.

If a significant portion of any future net leasehold acreage is undeveloped, and that acreage is not ultimately developed or does not become commercially productive, we could lose rights under these leases, and any such events could have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our financial condition, results of operations and cash available for distribution.

To the extent we acquire working interests in the future, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves, we could lose our rights under those leases if we do not timely develop such acreage. In addition, if we are required under any such oil and natural gas leases to drill wells that are commercially productive and we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our financial condition, results of operations and cash available for distribution may be highly dependent on successfully developing our undeveloped leasehold acreage.

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

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

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

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

If we acquire working interests in the future, 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 a lease 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 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.

Table of Contents

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, results of operations and cash available for distribution may be adversely affected.

Identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

To the extent we acquire working interests in the future, our ability to drill and develop identified potential drilling locations will depend on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results and the availability of water. 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. We 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 20-acre downspacing will produce at the same rates as those on 40-acre spacing. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill wells that we identify as dry holes in current and future drilling locations, our drilling success rate may decline and materially harm our business.

We will not be able to assure our unitholders that the analogies drawn 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 us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we identify will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those identified, which could adversely affect our business.

For information on Diamondback's identified potential drilling locations, see "Items 1 and 2. Business and Properties."

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

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. To the extent we acquire working interests in the future, the cost to renew our leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Any such losses of leases could materially and adversely affect the growth of our financial condition, results of operations and cash available for distribution.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition, results of operations and cash available for distribution.

To the extent we acquire working interests in the future, we may have exposure to credit risk through receivables from joint interest owners on properties we operate and receivables from purchasers of our oil and natural gas production. Joint interest receivables will arise from billing entities that own partial interests in any wells we operate. These entities will typically participate in our wells primarily based on their ownership in leases on which we wish to drill. We will generally be unable to control which co-owners participate in our wells.

We also may be subject to credit risk due to the concentration of oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. Generally, customers are not required to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition, results of operations and cash available for distribution.

Table of Contents

To the extent we depend upon certain significant purchasers for the sale of most of our oil and natural gas production, the loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce and adversely affect our results of operations and cash available for distribution.

To the extent we acquire working interests in the future, the availability of a ready market for any oil and natural gas we produce will depend on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. In addition, to the extent we depend upon certain significant purchasers for the sale of most of our oil and natural gas production, the loss of one or more of such purchasers, or their failure or inability to meet their obligations to us, could adversely affect our results of operations and cash available for distribution. We cannot assure our unitholders that we will have ready access to suitable markets for our oil and natural gas production if we acquire working interests in the future.

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

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

Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash available for distribution.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. During the last two years, parts of Texas have experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. To the extent we acquire working interests in the future, if we are unable to obtain water to use in our operations from local sources, or we are unable to effectively utilize flowback water, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash 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.

To the extent we acquire working interests in the future, our operations will involve utilizing the latest drilling and completion techniques. Risks that we will face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we will 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 we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in identified vertical drilling locations. Furthermore, certain of the new techniques we 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 we will 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 drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline.

The marketability of oil and natural gas production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our results of operations and cash available for distribution could be adversely affected.

To the extent we acquire working interests in the future, the marketability of our oil and natural gas production will depend in part upon the availability, proximity and capacity of transportation facilities, including gathering systems, trucks and pipelines, owned by third parties. We may not control these third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. For example, on certain occasions, 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 we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, could adversely affect our financial condition, results of operations and cash available for distribution.

Our operations will be subject to various governmental laws and regulations which require compliance that can be burdensome and expensive and could expose us to significant liabilities, which could adversely affect our cash available for distribution.

To the extent we acquire working interests in the future, our oil and natural gas operations will be 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 of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management.

Laws and regulations governing exploration and production may also affect production levels. To the extent we acquire working interests in the future, we will be 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.

If we acquire working interests in the future, we will also be 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. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. 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 our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our 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 and additional operating restrictions or delays.

To the extent we acquire working interests in the future, we expect to engage in hydraulic fracturing. Moreover, our current operators engage in hydraulic fracturing. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and natural gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. Moreover, the EPA announced in October 2011 that it was launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards in early 2015 that such wastewater must meet before being transported to a treatment plant. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." If adopted, the new pretreatment rules will require operators to pretreat wastewater before transferring it to a treatment facility that discharges to surface water. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

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 ("VOCs"), 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 rule seeks to achieve a 95% reduction in VOCs 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. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. Also, on December 19, 2014 the EPA released final updates and clarifications to the NSP standards. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources, with results of the study anticipated to be available March 2015. The White House Council on Environmental Quality is conducting an administration-wide review of hydraulic fracturing practices. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The RRC recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act to state regulators and on a public internet website. Additionally, on October 28, 2014, the RRC 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 also clarify the RRC'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 disposal well rule amendments became effective November 17, 2014. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. To the extent we acquire working interests, we expect to use hydraulic fracturing extensively in connection with the development and production of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we conduct operations, we may incur substantial costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, 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 are adopted that significantly restrict hydraulic fracturing, 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 legislative changes could cause operators to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us, to the extent we acquire working interests in the future, or our operators 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 or state legislation governing hydraulic fracturing.

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

To the extent we acquire working interests in the future, we may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us 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, frontier and other protected 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 may 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, we may be required to remediate contaminated properties operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our 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 operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. 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, our business, financial condition, results of operations 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 ability to conduct drilling activities in some of the areas where we operate.

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

If we acquire working interests in the future, the adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including rules which regulate emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the “tailoring rule”) in May 2010, and it also became effective January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA (“UARG v. EPA”), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in UARG v. EPA. In its preliminary guidance, EPA indicates it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

In addition, in August 2012, the EPA established NSP standards for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions.

The EPA has continued to adopt GHG regulations of other industries, such as the September 2013 proposed GHG rule that, if finalized, would set new source performance standards for new coal-fired and natural gas-fired power plants, which could have an adverse effect on our financial condition, results of operation and cash available for distribution to the extent we acquire working interests in the future. The EPA is also considering additional regulation of greenhouse gases as "air pollutants." As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a

Table of Contents

possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The U.S. Congress has not adopted such legislation at this time, but it may do so in the future, and many states continue to pursue regulations to reduce greenhouse gas emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, 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 has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados 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 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.

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

If we acquire working interests in the future, our drilling activities will be subject to many risks. For example, we will not be able to assure our unitholders that wells drilled by us will be productive or that we will recover all or any portion of our 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 our control, and increases in those costs can adversely affect the economics of a project. Further, our 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, results of operations 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.

If we acquire working interests in the future, we may operate in areas of high industry activity, which may make it difficult to hire, train or retain qualified personnel needed to manage and operate our assets.

If we acquire working interests in the future, our operations and drilling activity will likely be 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. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

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

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

To the extent we acquire working interests in the future, we will 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 we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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

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

Increased costs of capital could adversely affect our business.

Our business and operating results 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 operations. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and, to the extent we acquire working interests in the future, our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

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.

32

Table of Contents

- 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, including Wexford, may compete with us.

The board of directors of our general partner has adopted a policy to distribute an amount equal to the available cash we generate each quarter, which 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.

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 own and operate Diamondback's assets, 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. Because Diamondback provides services to us that are similar to those performed for itself, 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 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 common 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 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, including Wexford, 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 and Wexford, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Diamondback or Wexford may compete with us for investment opportunities and may own an interest in entities that compete with us. Further, Diamondback and its affiliates, including Wexford, 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 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, Diamondback and Wexford. 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

Table of Contents

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 common 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 common 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 common units is required to remove our general partner. As of December 31, 2014, Diamondback owns 88.4% of our common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common 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 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 common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common 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 unitholders. Our partnership agreement does not set a 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 on the common units, we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. 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. 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 to our unitholders.

We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford provides general finance and advisory services in exchange for a fee and certain expense reimbursement. This fee will reduce the amount of cash available for distribution to our 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 the 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

Table of Contents

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.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (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 97% of the common 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. If our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding common units, the ownership threshold to exercise the call right will be permanently reduced to 80%. 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. As of December 31, 2014, Diamondback owns 88.4% of our common units.

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

Table of Contents

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, 2014 we have 79,708,888 common units outstanding. 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 agreed to provide registration rights to Diamondback. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold.

We will incur increased costs as a result of being a publicly traded partnership.

Prior to the completion of our IPO in June 2014, we had no history operating as a publicly traded partnership. As a publicly traded partnership, we have incurred and will incur significant legal, accounting and other expenses that we did not incur prior to becoming a publicly trading partnership. In addition, the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC and NASDAQ, require, or will require, publicly traded entities to adopt various corporate governance practices that will further increase our costs. Before we are able to make distributions to our unitholders, we must first pay our expenses, including the costs of being a publicly traded partnership and other operating expenses. As a result, the amount of cash we have available for distribution to our unitholders will be affected by our expenses, including the costs associated with being a publicly traded partnership. We estimate that we will incur approximately $2.5 million of incremental costs per year associated with being a publicly traded partnership; however, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements, including those relating to accounting standards and disclosure about our executive compensation and internal control auditing requirements that apply to other public companies.

We are classified as an “emerging growth company” under Section 2(a)(19) of the Securities Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board (“PCAOB”) requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

If we fail to develop or 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.

Diamondback is a publicly traded corporation and has developed a system of internal controls for compliance with public reporting requirements. However, prior to the IPO, our predecessor had not been required to file reports with the SEC on a stand-alone basis. Upon the completion of the IPO, we became subject to the public reporting requirements of the Exchange Act. 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 develop and 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 will require 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. We must comply with Section 404 (except for the requirement for an auditor’s attestation report) beginning with our fiscal year ending December 31, 2015. Any failure to develop or 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.

Table of Contents

NASDAQ does not require a publicly traded 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.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. We would also be subject to certain state taxes. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to unitholders. Therefore, treatment of us as a corporation or the assessment of a material amount of entity-level taxation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Even if our unitholders do not receive any cash distributions from us, our unitholders will be required to pay taxes on their share of our taxable income.

Our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not our unitholders receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability with respect to that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation and depletion recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if they sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, a portion of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, may be unrelated business taxable income and may be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person may be required to file United States federal tax returns and pay tax on their share of our taxable income if it is treated as effectively connected income.

Table of Contents

Prospective unitholders who are a tax-exempt entities or non-U.S. persons should consult their tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of our common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Our counsel is unable to opine as to the validity of this approach. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly-traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to effect a short sale of common units. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. As of December 31, 2014 Diamondback owns 88.4% of the total interests in our capital and profits. Therefore, a transfer by Diamondback of all or a portion of its interests in us could result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Our unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

40

Table of Contents

In addition to federal income taxes, our unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if such unitholders do not live in any of those jurisdictions. We may be treated as doing business directly or indirectly in a number of jurisdictions and many of these jurisdictions impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. It is a unitholder's responsibility to file all U.S. federal, foreign, state and local tax returns.

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.

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
Market Information and Cash Distributions to Unitholders
Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM." Our common units began trading on June 18, 2014 at an initial public offering price of $26.00 per common unit. The following table shows the low and high sales price per common unit, as reported by the NASDAQ Global Select Market, for the periods indicated:

Period:	High	Low
Second quarter 2014 (beginning June 18, 2014)	$36.00	$31.00
Third quarter 2014	$34.50	$22.85
Fourth quarter 2014	$24.26	$13.79

There were three holders of record of our common units on February 18, 2015.

Cash Distribution Policy
The board of directors of our general partner has adopted a policy for us to distribute all available cash generated on a quarterly basis, beginning with the quarter ending September 30, 2014. Our first distribution of $0.25, included available cash for the period from June 23, 2014, the date of the close of the IPO, through September 30, 2014. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter will generally equal 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.

General Partner Interest
Our general partner owns a non-economic general partner interest and therefore is not entitled to receive cash distributions. However, it may acquire common units and other equity interests in the future and will be entitled to received pro rata distributions in respect of those equity interests.

Recent Sales of Unregistered Securities
In connection with our formation in February 2014, we issued (i) the non-economic general partner interest in us to Viper Energy Partners GP LLC and (ii) the 100.0% limited partner interest in us to Diamondback for $100.00. On June 23, 2014, we issued 70,450,000 common units to Diamondback in exchange for the ownership interests in Viper Energy Partners LLC. These issuances were exempt from registration under Section 4(a)(2) of the Securities Act.
Repurchases of Equity Securities
None.

42

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. We refer to Viper Energy Partners, LLC as “Viper Energy Partners LP Predecessor.” Viper Energy Partners LP Predecessor acquired its assets on September 19, 2013.

The contribution of Viper Energy Partners LP Predecessor to Viper Energy Partners LP was accounted for as a combination of entities under common control. Therefore, the following table presents the historical financial data of Viper Energy Partners LP as if Viper Energy Partners LP Predecessor and Viper Energy Partners LP were combined since inception.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the year ended December 31, 2014 and for the period from inception through December 31, 2013 and the balance sheet data as of December 31, 2014 and 2013 are derived from our audited consolidated financial statements included elsewhere in this Annual Report. For factors materially affecting the comparability of the information below, please see “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations-Results Presented and Factors Affecting the Comparability of Our Results to the Historical Financial Results of The Predecessor.”

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(in thousands)	
Statement of Operations Data:		
Royalty income	$77,767	$ 14,987
Costs and expenses:		
Production and ad valorem taxes	5,377	972
Depletion	27,601	5,199
General and administrative expenses	3,198	—
General and administrative expenses—related party	1,174	87
Total costs and expenses	37,350	6,258
Income from operations	40,417	8,729
Other income (expense)		
Interest expense	(487)	—
Interest expense—related party, net of capitalized interest	(10,755)	(5,741)
Other income	459	—
Total other income (expense), net	(10,783)	(5,741)
Net income	$29,634	$ 2,988
Allocation of net income:		
Net income attributable to the period through June 22, 2014	$7,021	
Net income attributable to the period June 23, 2014 through December 31, 2014	22,613	
	$29,634	
Net income attributable to common limited partners per unit:		
Basic	$0.29	
Diluted	$0.29	
Cash distributions declared per unit		
Statement of Cash Flow Data:		
Net cash provided by (used in):		
Operating activities	$51,813	$ 4,845
Investing activities	(96,815)	(4,083)
Financing activities	59,350	—
Other Financial Data:		
Adjusted EBITDA(1)	$70,579	$ 13,928
Balance Sheet Data (at period end):		
Cash and cash equivalents	$15,110	$ 762
Total assets	537,402	453,023
Total liabilities	2,051	450,035
Unitholders' equity/Members' equity	535,351	2,988

(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 define Adjusted EBITDA as net income plus interest expense, net of capitalized interest, non-cash unit-based compensation expense and depletion. Adjusted EBITDA is not a measure of net income as determined by United States' generally accepted accounting principles ("GAAP"). 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. We exclude the items listed above from net income 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. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. 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. 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 the most directly comparable GAAP financial measure for the periods indicated.

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(in thousands)	
Net Income	$29,634	$2,988
Interest expense	487	—
Interest expense—related party, net of capitalized interest	10,755	5,741
Non-cash unit-based compensation expense	2,102	—
Depletion	27,601	5,199
Adjusted EBITDA	$70,579	$13,928

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 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. As of December 31, 2014, the general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 88.4% limited partner interest in us. Diamondback also owns and controls the 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.

Recent Developments

Public Offerings

Prior to the completion of our IPO on June 23, 2014, Diamondback owned all of the general and limited partner interests in us. On June 23, 2014, we completed our IPO of 5,750,000 common units representing limited partner interests at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. We received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the IPO, Diamondback contributed all of the membership interests in our predecessor to us in exchange for 70,450,000 common units. In addition, in exchange for the contribution of our predecessor, we agreed to distribute the net proceeds from the IPO and all cash and the royalty income receivable on hand at the time of the IPO to Diamondback. We distributed $148.8 million to Diamondback during 2014, representing the net proceeds of the IPO and the royalty income receivable on hand at the time of the IPO. The contribution of the predecessor to us was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

On September 19, 2014, we completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and we received net proceeds of approximately $94.8 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

Sources of Our Revenue

Our revenues are 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. For the year ended December 31, 2014, our revenues were derived 91% from oil sales, 5% from natural gas liquid sales and 3% from natural gas sales. For the period from inception through December 31, 2013, our revenues were derived 93% from oil sales, 5% from natural gas liquid sales and 2% from natural gas sales. As a result, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Our revenues 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 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On December 31, 2014, the West Texas Intermediate posted price for crude oil was $53.45 per Bbl and the Henry Hub spot market price of natural gas was $3.14 per MMBtu. Over the past several months, oil prices have declined from over $105.00 per Bbl in June 2014 to below $45.00 per Bbl in January 2015 due in large part to increasing supplies and weakening demand growth. Lower prices may not only decrease our revenues, 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 determined at the discretion of our lenders.

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 gas properties.

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 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.

In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford, pursuant to which Wexford provides general financial and strategic advisory services to us and our general partner in exchange for a $0.5 million annual fee and certain expense reimbursement.

Our predecessor incurred costs for overhead, including the cost of management, operating and administrative services provided under the shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback, audit and other fees for professional services and legal compliance. In connection with the closing of

the IPO, the shared services agreement with Diamondback E&P LLC was terminated.
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

We are organized as a pass-through entity for income tax purposes. As a result, our partners are responsible for federal income taxes on their share of our taxable income.

We are subject to the Texas margin tax. Any amounts related to operations for 2013 or for the period in 2014 prior to the closing of the IPO on June 23, 2014 will be included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the year ended December 31, 2014 or the period from inception through December 31, 2013, so no amount has been provided in the accompanying financial statements of our predecessor.

Results of Operations

Results Presented and Factors Affecting the Comparability of Our Results to the Historical Financial Results of Our Predecessor

Viper Energy Partners LP was formed on February 27, 2014 and did not own any assets prior to the contribution of the predecessor to us on June 17, 2014. The assets of our predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired on September 19, 2013. See Note 3—Acquisitions, to our accompanying audited consolidated financial statements. The contribution of our predecessor to us on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. Therefore, the financial and operating data below represent our predecessor's operations for periods prior to June 17, 2014 and, for periods on and after June 17, 2014, the financial and operating data represent the combination of the predecessor and our operations.

Our results of operations and our future results of operations may not be comparable to the historical results of operations of our predecessor for the periods presented, primarily for the reasons described below:

Long-Term Debt

- In connection with the closing of the IPO, the subordinated note issued by our predecessor to Diamondback effective September 19, 2013 was converted to equity; therefore, we no longer have the note payable and related interest expense.
- On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be redetermined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2014, the borrowing base was set at $110.0 million and we had no outstanding borrowings.

General and Administrative

- We anticipate incurring incremental general and administrative expenses of approximately $2.5 million annually as a result of being a publicly traded partnership, consisting of expenses associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NASDAQ Global Select Market listing, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, director and officer insurance and director compensation.
- The partnership agreement requires us to reimburse the 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, 2014, we reimbursed our general partner $0.9 million for these expenses.

47

Table of Contents

- On June 17, 2014, under the Long Term Incentive Plan, or LTIP, adopted in connection with the IPO, we granted awards of an aggregate of 2,500,000 unit options under the LTIP to executive officers of the general partner. For the year ended December 31, 2014, we incurred $2.1 million of unit–based compensation.
- In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford pursuant to which Wexford provides general financial and strategic advisory services to us and our general partner in exchange for a $0.5 million annual fee and certain expense reimbursement. For the year ended December 31, 2014, we incurred costs of $0.3 million, under the advisory services agreement.
- In connection with the closing of the IPO, we 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 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 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 would 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.

Table of Contents

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

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(In thousands)	
Operating Results:		
Royalty income	$77,767	$14,987
Costs and expenses:		
Production and ad valorem taxes	5,377	972
Depletion	27,601	5,199
General and administrative expenses	3,198	—
General and administrative expenses—related party	1,174	87
Total costs and expenses	37,350	6,258
Income from operations	40,417	8,729
Other income (expense)		
Interest expense	(487)	—
Interest expense—related party, net of capitalized interest	(10,755)	(5,741)
Other income	459	—
Total other income (expense), net	(10,783)	(5,741)
Net income	$29,634	$2,988
Allocation of net income:		
Net income attributable to the period through June 22, 2014	$7,021	
Net income attributable to the period June 23, 2014 through December 31, 2014	22,613	
	$29,634	
Production Data:		
Oil (Bbls)	856,541	150,815
Natural gas (Mcf)	648,808	108,264
Natural gas liquids (Bbls)	144,074	19,971
Combined volumes (BOE)	1,108,750	188,830
Daily combined volumes (BOE/d)	3,038	1,798
% Oil	77 %	80 %

Royalty Income

Our royalty income for the year ended December 31, 2014 and for the period from inception to December 31, 2013 was $77.8 million and $15.0 million, respectively.

Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes. Our operators received an average of $82.98 per Bbl of oil, $27.59 per Bbl of natural gas liquids and $4.18 per Mcf of natural gas for the volumes sold for the year ended December 31, 2014. Our operators received an average of $92.07 per Bbl of oil, $35.30 per Bbl of natural gas liquids and $3.67 per Mcf of natural gas for the volumes sold for the period from inception to December 31, 2013.

Table of Contents

General and Administrative Expenses
The general and administrative expenses primarily reflect unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the year ended December 31, 2014 and for the period from inception to December 31, 2013, we incurred general and administrative expenses of $4.4 million and $0.1 million, respectively.

Net Interest Expense
The net interest expense for the year ended December 31, 2014 reflects the interest incurred under our credit agreement. The net interest expense for the year ended December 31, 2014 and for the period from inception through December 31, 2013 primarily relates to interest incurred under the subordinate note of the predecessor. Net interest expense for the year ended December 31, 2014 and for the period from inception through December 31, 2013 was $11.2 million and $5.7 million, respectively.

Adjusted EBITDA

Adjusted EBITDA is used as a supplemental non-GAAP financial measure 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 period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA to evaluate cash flow available to pay distributions to our unitholders.

We define Adjusted EBITDA as net income (loss) plus interest expense, net of capitalized interest, non-cash unit-based compensation and depletion expense. Adjusted EBITDA is not a measure of the 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 historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered an alternative to net income, royalty income, cash flow from operating activities or any other measure of financial performance or liquidity presented 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, 2014	Period From Inception Through December 31, 2013
	(In thousands)	
Net Income	$29,634	$2,988
Interest expense	487	—
Interest expense—related party, net of capitalized interest	10,755	5,741
Non-cash unit-based compensation expense	2,102	—
Depletion	27,601	5,199
Adjusted EBITDA	$70,579	$13,928

Table of Contents

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations and equity and debt financings, including borrowings under our credit agreement, and our primary uses of cash will be for paying distributions to our unitholders and for replacement and growth capital expenditures, including the acquisition, development and exploration of oil and natural gas properties. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, and general economic, financial, competitive, legislative, regulatory and other factors.

Our partnership agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it will be in the best interests of our unitholders if we distribute a substantial portion of the cash we generate from operations. The board of directors of our general partner has adopted a policy to distribute an amount equal to the available cash we generate each quarter to our unitholders. Our first distribution of $0.25 per unit included available cash for the period from June 23, 2014, the date of the close of the IPO, through September 30, 2014. This distribution included a total of $17.6 million distributed to Diamondback. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter will generally equal 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.

Our Credit Agreement

On July 8, 2014, we entered into a $500.0 million secured revolving credit agreement with Wells Fargo as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, matures on July 8, 2019. As of December 31, 2014, the borrowing base was set at $110.0 million and we had no outstanding borrowings.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of our and our subsidiaries' 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 debt to EBITDAX	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

EBITDAX will be annualized beginning with the quarter ended September 30, 2014 and ending with the quarter ending March 31, 2015

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million 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.

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

Table of Contents

Cash Flows

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

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(in thousands)	
Cash Flow Data:		
Cash flows provided by operating activities	$51,813	$4,845
Cash flows used in investing activities	(96,815)	(4,083)
Cash flows provided by financing activities	59,350	—
Net increase in cash	$14,348	$762

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for oil and natural gas. 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

The purchase of oil and natural gas interests accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $96.8 million and $4.1 million during the year ended December 31, 2014 and the period from inception to December 31, 2013, respectively.

During the year ended December 31, 2014, we spent approximately $57.7 million on acquisitions of mineral interests underlying approximately 10,364 gross (3,261) net acres in the Midland and Delaware basins and approximately $33.9 million for a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests.

Financing Activities

Net cash provided by financing activities of $59.4 million during the year ended December 31, 2014 primarily relates to our equity offerings. From the sale of common units in our IPO and the September 19, 2014 equity offering, we received net proceeds of approximately $232.2 million, net of offering expenses and underwriting discounts and commissions. In connection with the closing of the IPO, we agreed to distribute to Diamondback the net proceeds from the IPO and all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.6 million. During 2014, we distributed $148.8 million to Diamondback as part of the IPO transactions. We used a portion of the net proceeds from our September 19, 2014 equity offering to repay borrowings under our credit agreement of $78.0 million. We also distributed $19.9 million to our unitholders for our third quarter 2014 distribution. We did not use any cash for financing activities during the period from inception to December 31, 2013.

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2014.

	Payments Due by Period				
	Total	2015	2016-2017	2018-2019	2020 & Beyond
	(in thousands)				
Interest and commitment fees under our credit agreement[1]	$1,857	$413	$825	$619	$—
	$1,857	$413	$825	$619	$—

Table of Contents

(1) This table reflects only the minimum amount of interest and commitment fees due, which as of December 31, 2014 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 to the consolidated financial statements and related notes, which is included elsewhere in this Annual Report

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 gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties and unit–based compensation.

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.

Oil and Natural Gas Reserve Quantities and Standardized Measure of Future Net Revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and 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 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

Table of Contents

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 interests represent the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Revenue is recorded when title passes to the purchaser.

Holders of royalty interests have no rights or obligations to explore, develop or operate the property and do not incur any of the costs of exploration, development and operation of the property.

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 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 and costs used are those as of the end of the appropriate quarterly period.

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 accompanying audited consolidated financial statements. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and forfeiture rate assumptions. Estimates of the fair value of unit options granted during the year ended December 31, 2014, were completed using a Black-Scholes option valuation model, which requires us to make several assumptions.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (“ASU”) 2014-09, “Revenue from Contracts with Customers”. ASU 2014-09 supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2016, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. We are currently evaluating the impact, if any, that the adoption of ASU 2014-09 will have on our financial position, results of operations, and liquidity.

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 period from inception through the year ended December 31, 2014. 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

Table of Contents

pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which our properties are located.

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, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (70%) and Permian Transport & Trading (15%). For the period from inception to December 31, 2013, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (59%) and Permian Transport & Trading (19%). 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.
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 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We entered into this credit agreement on July 8, 2014, and as of December 31, 2014, we had no outstanding borrowings. On September 18, 2014, the last date on which borrowings were outstanding under our credit agreement, such borrowings bore interest at a weighted average rate of 2.16% An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $780,000 based on the $78.0 million outstanding in the aggregate under our credit agreement on September 18, 2014.

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

Table of Contents

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, 2014, 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, 2014, our disclosure controls and procedures are effective.

Management''s Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm. This Annual Report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

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, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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 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.

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our general partner. 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 (as of January 31, 2015)	Position With Our General Partner
Travis D. Stice	53	Chief Executive Officer, Director
Teresa L. Dick	45	Chief Financial Officer, Senior Vice President and Assistant Secretary
Russell Pantermuehl	55	Vice President-Reservoir Engineering
Elizabeth E. Moses	57	Vice President-Business Development and Land
Randall J. Holder	61	Vice President, General Counsel and Secretary
Steven E. West	54	Executive Chairman, Director
W. Wesley Perry	58	Director
W. Duncan Kennedy	53	Director
Michael L. Hollis	39	Director
James L. Rubin	30	Director
Rosalind Redfern Grover	73	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. Prior to his current position with Diamondback, Mr. Stice served as its 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 26 years of experience in production operations, reservoir engineering, production engineering and unconventional oil and gas exploration and over 18 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 25-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.
Teresa L. Dick. Ms. Dick has served as Chief Financial Officer, Senior Vice President and Assistant Secretary of our general partner since February 2014. She has also served as Diamondback's Chief Financial Officer and Senior Vice President since November 2009 and as its Corporate Controller from November 2007 until November 2009. 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 19 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 Vice President-Reservoir Engineering of our general partner since February 2014. He has also served as Diamondback's Vice President-Reservoir Engineering since August 2011, and, prior to his current position at 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.

Elizabeth E. Moses. Ms. Moses has served as Vice President-Business Development and Land since November 2014. She has also served as Vice President-Business Development and Land for Diamondback since January 2014. Prior to that position, Ms. Moses worked for Diamondback as a Land Manager from February 2013 until December 2013. Ms. Moses worked as an independent consulting petroleum landman from 2003 until she joined us in February 2013. In her role as an independent consultant, Ms. Moses consulted with various clients in the oil and gas industry and supervised other subconsultants. Ms. Moses has over 34 years of experience as a landman in the oil and gas industry. Ms. Moses received her Bachelor of Business Administration degree from Steven F. Austin State University.

Randall J. Holder. Mr. Holder has served as Vice President, General Counsel and Secretary of our general partner since February 2014. Mr. Holder joined Diamondback in November 2011 as General Counsel and Vice President and also serves as Secretary. Prior to joining Diamondback, Mr. Holder served as General Counsel and Vice President for Great White Energy Services LLC, an oilfield services company, from November 2008 to November 2011. He served as Executive Vice President and General Counsel for R.L. Hudson and Company, a supplier of molded rubber and plastic components, from February 2007 to October 2008. He was in private practice of law and a member of Holder Betz LLC from February 2005 to February 2007. Mr. Holder served as Vice President and Assistant General Counsel for Dollar Thrifty Automotive Group, a vehicle rental company, from January 2003 to February 2005 and as Vice President and General Counsel for Thrifty Rent-A-Car System, Inc., a vehicle rental company, from September 1996 to December 2002. He also served as Vice President and General Counsel for Pentastar Transportation Group, Inc. from November 1992 to September 1996, which was wholly-owned by Chrysler Corporation. Mr. Holder started his legal career with Tenneco Oil Company where he served as a Division Attorney providing legal services to the company’s mid-continent division for ten years. He received a Juris Doctorate degree from Oklahoma City University.

Steven E. West. Mr. West has served as a director and Executive Chairman of our general partner since February 2014. 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. Since January 2011, Mr. West has been 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 holds 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.

W. Wesley Perry. Mr. Perry has been a member of the board of directors of our general partner since June 2014. He served as President of EGL Resources, Inc., an oil and gas operations company based in Texas and New Mexico, from January 1994 until July 2008, before becoming the Chief Executive Officer. He has also served as manager of PBEX, LLC since July 2012. Mr. Perry has served as a director of Genie Energy, Ltd. from September 2009 and is chairman of the audit committee. He also serves as Chairman of Genie Energy International Corporation. He served as a director of UTG, Inc. from July 2005 to June 2013. He served as a director of American Capital Insurance Company and Texas Imperial Life Insurance Company from 2006 to 2009 and as a director of Western National Bank from 2005 to 2009. Mr. Perry has owned and operated SES Investments, Ltd., an oil and gas investment company, since 1980. He served as the Mayor of Midland, Texas, from January 2008 through January 2014. He also served on the Midland City Council as an at-large councilperson from 2002 to 2008. Mr. Perry holds 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.

W. Duncan Kennedy. Mr. Kennedy has been a member of the board of directors of our general partner since September 2014. He has served as President of THE NINETY-SIX CORPORATION since June 2002, and as Vice President of Kennedy Minerals, Ltd since 2005. Both companies are engaged in oil and gas exploration and mineral acquisition. Mr. Kennedy graduated from Southern Methodist University with a Bachelor of Arts degree in Geology.

We believe that Mr. Kennedy’s extensive experience in the oil and gas industry qualifies him to serve on the board of directors of our general partner.

Michael L. Hollis. Mr. Hollis has been a member of the board of directors of our general partner since June 2014. He has served as Vice President-Drilling of Diamondback since September 2011. Prior to his current position with Diamondback, Mr. Hollis served in various roles, most recently as drilling manager at Chesapeake Energy

Corporation, an oil and gas exploration company, from June 2006 to September 2011. He worked for ConocoPhillips Company as a senior drilling engineer from January 2002 to June 2006 and as a process engineer from 2001 to 2003. Mr. Hollis also worked as a production engineer for Burlington Resources from 1998 to 2001 as well as from June 2003 to January 2004. Mr. Hollis received his Bachelor of Science degree in Chemical Engineering from Louisiana State University.

We believe that Mr. Hollis' extensive experience in the oil and gas industry, including at Diamondback, qualifies 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 seven directors, three of whom are independent as defined under the independence standards established by NASDAQ and the Exchange Act. W. Wesley Perry, W. Duncan Kennedy and Rosalind Redfern Grover serve as the independent members of the board of directors of our general partner.

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 Executive Chairman. Steven E. West serves as the Executive 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 Executive 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 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 Executive 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

Subsequent to our IPO, the board of directors of our general partner met once during 2014. Each director attended this meeting of the board and each of the meetings of the committees on which he or she served that occurred during 2014.

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 met twice during 2014. 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, W. Duncan Kennedy and Rosalind Redfern Grover currently serve on the audit committee, and Mr. Perry serves as the chairman. The board or directors of our general partner has determined that each of W. Wesley Perry, W. Duncan Kennedy and Rosalind Redfern Grover meet the independence and experience standards established by 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, W. Duncan Kennedy and Rosalind Redfern Grover are the members of the conflicts committee. The conflicts committee was formed in January 2015.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act, to file reports of beneficial ownership and reports of changes in beneficial ownership of such securities with the SEC. Directors, officers and greater than 10% unitholders are required by SEC regulations to furnish to us copies of all Section 16(a) forms they file with the SEC.

Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of our general partner, we believe that during the year ended December 31, 2014 the officers and directors of our general partner and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a), with the exception of an inadvertent omission subsequently reported on a Form 4 or an amended Form 4, as applicable, for each of Michael L. Hollis, Teresa L. Dick, Travis D. Stice, W. Wesley Perry, Russell Pantermuehl and Randall J. Holder relating to such person's purchases of common units in the Partnership's directed unit program conducted in connection with the IPO.

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. In addition, we and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford provides general finance and advisory services in exchange for a fee and certain expense reimbursement. See "Item 13. Certain Relationships and Related Party Transactions, and Director Independence–Advisory Services Agreement."

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 both us and Diamondback and allocate their time between managing our business and managing the business of Diamondback. 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 Viper Energy Partners LP Long Term Incentive Plan (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 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 2014 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 2014 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 set forth in Diamondback's 2014 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.

Our general partner has made grants under the LTIP of (a) phantom units to the non-employee directors of our general partner (see "-Director Compensation" below for information regarding those awards) and (b) at the time of our IPO, an aggregate of 2,500,000 unit options to the executive officers of our general partner. Each unit option entitles the recipient to purchase one of our common units. In accordance with the LTIP, the exercise price of the unit options granted may not be less than the market value of our common units on the date of grant. The outstanding unit options have an exercise price of $26.00 per unit, which was the price to the public in our IPO. Subject to accelerated vesting upon certain specified events, a third of the unit options will vest each year on the anniversary of their grant, and the options will be automatically exercised, to the extent vested, on the earlier to occur of the three year anniversary of the date of grant or the occurrence of a change in control. These grants of unit options pursuant to the LTIP will be reflected in the tables contained in Diamondback's 2014 proxy statement under the heading "Compensation Discussion and Analysis."

Administration

The LTIP is administered by the board of directors of our general partner. The board of directors of our general partner administers the LTIP 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 will be determined by the committee in the terms of the relevant award agreement.

Table of Contents

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
W. Duncan Kennedy
Michael L. Hollis
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 $47,500 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. Our directors also receive a fee of $1,000 for attending each in-person meeting of the board of directors or its committees and $500 for attending each telephone meeting. In addition, our directors are reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each non-employee director receives annual grants of equity-based awards under the LTIP for so long as he or she serves as a director.

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 2014 for their services on the board:

Director Compensation
for the Year Ended December 31, 2014(e)

Name	Fees Earned or Paid in Cash (a)	Unit Awards (b)	Total
Rosalind Redfern Grover(c)	$1,291	$—	$1,291
W. Duncan Kennedy(d)	17,344	130,054	147,398
W. Wesley Perry(d)	31,250	130,054	161,304
James L. Rubin(d)	23,750	130,054	153,804
Steven E. West(d)	23,750	130,054	153,804

Table of Contents

(a) This column reflects the value of a director's annual retainer, as well as the additional payments for committee membership, committee chairmanship and meeting attendance.

(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 FASB Accounting Standards Codification Topic 718, "Compensation - Stock Compensation." As of December 31, 2014, each of Messrs. Kennedy, Perry, Rubin and West had 6,666 phantom units outstanding, and Ms. Grover had no unit awards outstanding.

(c) Ms. Grover was appointed to the board of directors of our general partner on December 22, 2014. The amounts reported in this table for Ms. Grover are prorated for her time served on the board of directors of our general partner in 2014.

(d) Each of Messrs. Kennedy, Perry, Rubin and West received a grant of 6,666 phantom units on November 5, 2014, of which 2,222 vested on the date of grant and settled on November 10, 2014, pursuant to the LTIP, with each unit having a grant date fair value of $19.51. Each of Messrs. Kennedy's, Perry's, Rubin's and West's remaining 4,444 phantom units will vest and settle in two equal annual installments beginning on June 17, 2015. Each phantom unit is the economic equivalent of one of our common units.

(e) Messrs. Stice and Hollis are both directors of our general partner, but Mr. Stice is also an executive officer of our general partner and Mr. Hollis is an employee of Diamondback E&P LLC. Each of Messrs. Stice and Hollis have received awards pursuant to the LTIP for their service as an executive officer or employee, respectively, and unrelated to their service as directors. These awards are reflected in the tables contained in Diamondback's 2014 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. Hollis, a director of our general partner, is also an executive officer of Diamondback. 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 Messrs. Stice and Hollis are made by Diamondback and Messrs. Stice and Hollis do 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 "Item 1. Business and Properties-Our Relationship with Diamondback" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" for more information about relationships among us, our general partner and Diamondback.

Compensation Policies and Practices as They Relate to Risk Management

We do not have any employees. We are managed and operated by the directors and officers of our general partner and employees of Diamondback perform services on our behalf. Please read "-Compensation Discussion and Analysis" and "Items 1 and 2. Business and Properties-Our Relationship with Diamondback" for more information about this arrangement. For an analysis of any risks arising from Diamondback's compensation policies and practices, please read Diamondback's 2014 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

The following table presents information regarding the beneficial ownership of our common units as of February 18, 2015 by:

- our general partner;
- each of our general partner's directors and executive officers;
- each unitholder known by us to beneficially hold 5% or more of our common units; and
- all of our general partner's directors and executive officers as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. In computing beneficial ownership of each person, all amounts exclude common units issuable upon the exercise of outstanding options or the vesting of phantom units that are not exercisable or vested as of February 18, 2015 or

Table of Contents

within 60 days of February 18, 2015. Unless otherwise noted, the address for each beneficial owner listed below is 500 West Texas Avenue, Suite 1200, Midland, Texas 79701.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Diamondback(1)	70,450,000	88%
Viper Energy Partners GP LLC	-	-
Travis D. Stice (2)	37,500	*
Teresa L. Dick (2)	10,000	*
Russell Pantermuehl (2)	30,000	*
Elizabeth E. Moses (2)	19,200	*
Randall J. Holder	5,000	*
Steven E. West (3)	-	-
W. Wesley Perry (4)	21,222	*
W. Duncan Kennedy (4)	2,222	-
Michael L. Hollis (2)	51,500	*
James L. Rubin (3)	-	-
Rosalind Redfern Grover	-	-
All directors and executive officers as a group (11 persons)	153,000	*

*Less than 1%

(1) Diamondback Energy, Inc. is a publicly traded company. The directors of Diamondback are Travis D. Stice, Steven E. West, Michael P. Cross, David L. Houston and Mark L. Plaumann.

(2) Excludes 1,250,00, 250,000, 250,000, 250,000, 125,000 and 125,000 unit options granted to Mr. Stice, Mr. Pantermuehl, Mr. Hollis, Ms. Moses, Ms. Dick and Mr. Holder, respectively. See "Item 11. Executive Compensation-Compensation Discussion and Analysis-Long-Term Incentive Plan" for additional information regarding these unit options.

(3) Excludes 2,222 common units (representing vested phantom units previously granted to such director) and 4,444 unvested phantom units that will vest in two equal annual installments beginning on July 17, 2015, all of which have been assigned by Messrs. West and Rubin to Wexford under their terms of employment with Wexford.

(4) Excludes 4,444 phantom units that will vest in two equal annual installments beginning on July 17, 2015.

The following table sets forth, as of February 18, 2015, the number of shares of common stock of Diamondback beneficially owned by Wexford and each of the directors and executive officers of our general partner and all directors and executive officers of our general partner as a group.

Table of Contents

Name of Beneficial Owner	Shares of Diamondback Common Stock Beneficially Owned(1) Amount and Nature of Beneficial Ownership	Percentage of Class
DB Energy Holdings LLC(2)	2,748,534	4.7%
Travis D. Stice(3)	138,554	*
Teresa L. Dick(4)	22,444	*
Russell Pantermuehl(5)	37,755	*
Elizabeth Moses(6)	25,472	
Randall J. Holder(7)	4,225	0
Steven E. West(8)	0	*
W. Wesley Perry	0	0
W. Duncan Kennedy	0	0
Michael L. Hollis(9)	31,100	*
James L. Rubin	0	0
Rosalind Redfern Grover	0	0
All directors and executive officers as a group (11 persons)	259,550	*

*Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, shares of common stock subject to options held by that person that are exercisable as of February 18, 2015, or exercisable within 60 days of February 18, 2015, are 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 58,900,083 shares of common stock outstanding as of February 18, 2015. 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 February 18, 2015 or within 60 days of February 18, 2015.

(2) Based solely on Schedule 13D/A filed with the SEC on February 11, 2015 by DB Energy Holdings LLC (“DB Holdings”), Wexford Spectrum Fund, L.P. (“WSF”), Wexford Catalyst Fund, L.P. (“WCF”), Spectrum Intermediate Fund Limited (“SIF”), Catalyst Intermediate Fund Limited (“CIF,” and together with DB Holdings, WSF, WCF and SIF, the “Funds”), Wexford, Wexford GP LLC (“Wexford GP”), Charles E. Davidson (“Mr. Davidson”), and Joseph M. Jacobs (“Mr. Jacobs”). DB Holdings is a holding company managed by Wexford. WSF, WCF, SIF and CIF are investment funds managed by Wexford. Wexford is an investment advisor registered with the SEC, and manages a series of investment funds. Wexford GP is the general partner of Wexford. Mr. Davidson and Mr. Jacobs are the managing members of Wexford GP. DB has shared voting and dispositive power over 2,748,534 shares. WSF has shared voting and dispositive power over 32,793 shares. WCF has shared voting and dispositive power over 5,181 shares. SIF has shared voting and dispositive power over 108,477 shares. CIF has shared voting and dispositive power over 20,327 shares. Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs have shared voting and dispositive power over 2,988,920 shares. Wexford may, by reason of its status as manager or investment manager of the Funds, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Wexford GP may, as the General Partner of Wexford, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Each of Mr. Davidson and Mr. Jacobs may, by reason of his status as a controlling person of Wexford GP, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Each of Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs disclaims beneficial ownership of the securities owned by the Funds except, in the case of Mr. Davidson and Mr. Jacobs, to the extent of their respective interests in the Funds.

(3) Includes options to purchase 75,000 shares of Diamondback common stock and 14,285 restricted stock units, each of which will vest on April 18, 2015 (within 60 days of February 18, 2015). Excludes 8,334 restricted stock units that will vest on January 2, 2016 and 23,899 restricted stock units that will vest in two approximately equal annual installments beginning on January 2, 2016. Also excludes 25,000 performance-based restricted stock units awarded to Mr. Stice on February 27, 2014 and 35,833 performance-based restricted stock units awarded to Mr. Stice on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively.

Table of Contents

(4) Includes shares issuable upon exercise of options to purchase 12,510 shares of Diamondback common stock, all of which have vested, and 9,934 shares of Diamondback common stock held by Ms. Dick. Excludes options to purchase 12,500 shares of common stock, which will vest on September 1, 2015, and 11,645 restricted stock units, of which 4,285 will vest on September 1, 2015, 2,360 will vest on January 2, 2016 and 5,000 will vest in two equal annual installments beginning on January 2, 2016. Also excludes 7,080 performance-based restricted stock units awarded to Ms. Dick on February 27, 2014 and 7,500 performance-based restricted stock units awarded to Ms. Dick on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively.

(5) Includes shares issuable upon exercise of options to purchase 20,000 shares of Diamondback common stock, all of which have vested, and 17,755 shares of Diamondback common stock held by Mr. Pantermuehl. Excludes options to purchase 25,000 shares of common stock, which will vest on August 15, 2015, and 18,164 restricted stock units, of which 8,572 will vest on August 15, 2015, 2,925 will vest on January 2, 2016 and 6,667 will vest in two approximately equal annual installments beginning on January 2, 2016. Also excludes 8,775 performance-based restricted stock units awarded to Mr. Pantermuehl on February 27, 2014 and 10,000 performance-based restricted stock units awarded to Mr. Pantermuehl on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively.

(6) Includes options to purchase 12,500 shares of Diamondback common stock, all of which have vested, and 12,972 shares of Diamondback common stock held by Ms. Moses. Excludes options to purchase 25,000 shares of common stock, which will vest in two equal annual installments beginning on February 1, 2016, and 6,923 restricted stock units, of which 2,340 will vest on January 2, 2016 and 4,583 will vest in two approximately equal annual installments beginning on January 2, 2016. Also excludes 7,020 performance-based restricted stock units awarded to Ms. Moses on February 27, 2014 and 6,875 performance-based restricted stock units awarded to Ms. Moses on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively. Also excludes 5,600 shares of Diamondback's common stock previously held by Ms. Moses' spouse, which he sold.

(7) Includes 4,225 shares of Diamondback common stock held by Mr. Holder. Excludes options to purchase 12,500 shares of common stock, which will vest on November 18, 2015, and 10,454 restricted stock units, of which 4,285 will vest on November 18, 2015, 2,280 will vest on January 2, 2016 and 3,889 will vest in two approximately equal annual installments beginning on January 2, 2016. Also excludes 6,840 performance-based restricted stock units awarded to Mr. Holder on February 27, 2014 and 5,833 performance-based restricted stock units awarded to Mr. Holder on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively.

(8) Excludes 7,600 shares of Diamondback common stock (representing vested restricted stock units previously granted to Mr. West) and 1,868 unvested restricted stock units that will vest in two equal annual installments beginning on July 1, 2015, all of which were assigned by Mr. West to Wexford under the terms of Mr. West's employment with Wexford.

(9) Includes shares issuable upon exercise of options to purchase 13,345 shares of Diamondback common stock, all of which have vested, and 17,755 shares of Diamondback common stock held by Mr. Hollis. Excludes options to purchase 25,000 shares of Diamondback common stock, which will vest on September 12, 2015, and 18,164 restricted stock units, of which 8,572 will vest on September 12, 2015, 2,925 will vest on January 2, 2016 and 6,667 will vest in two approximately equal annual installments beginning on January 2, 2016. Also excludes 8,775 performance-based restricted stock units awarded to Mr. Hollis on February 27, 2014 and 10,000 performance-based restricted stock units awarded to Mr. Hollis on February 5, 2015, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to the Diamondback's peer group during the three-year performance periods ending on December 31, 2015 and December 31, 2016, respectively.

Securities Authorized For Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2014:

67

Table of Contents

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	2,517,776	$26.00 (2)	6,617,336

(1) Our general partner adopted the LTIP in connection with the IPO in June 2014.
(2) Reflects the exercise price for each of the 2,500,000 outstanding unit options.

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.

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.

Contribution Agreement

On June 17, 2014, in connection with the closing of the IPO, we entered into a contribution agreement that effected, among other things, the transfer of the ownership interests in Viper Energy Partners LLC to us in exchange for 70,450,000 common units issued to Diamondback and our agreement to distribute to Diamondback all cash and the royalty income receivable on hand at the time of the IPO and the net proceeds from the IPO. During the year ended December 31, 2014, we distributed $148.8 million to Diamondback in respect of this agreement. While we believe this agreement is on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it was not the result of arm's-length negotiations. All of the transaction expenses incurred in connection with these transactions were paid from the proceeds of the IPO.

Payments to our General Partner and its Affiliates

Under the terms of our partnership agreement, we are required to reimburse the 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 the general partner in connection with operating our 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 us or on our behalf and expenses allocated to the general partner by its affiliates. The general partner is entitled to determine the expenses that are allocable to us. For the year ended December 31, 2014 (subsequent to our IPO), we reimbursed the general partner and its affiliates an aggregate of $0.9 million in respect of this obligation and, at December 31, 2014, owed the general partner $4,000.

Distributions paid to Diamondback

Diamondback is entitled to receive its pro rata portion of the distributions we make in respect of our common units. During the year ended December 31, 2014 (subsequent to our IPO), Diamondback received such distributions in the amount of $17.6 million.

Table of Contents

Registration Rights Agreement

On June 23, 2014, in connection with the IPO, we entered into a registration rights agreement with Diamondback. Pursuant to the registration rights agreement, we are required to file a registration statement to register the common units issued to Diamondback. 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.

Advisory Services Agreement

On June 23, 2014, in connection with the closing of the IPO, we entered into an advisory services agreement with Wexford under which Wexford provides us and our general partner with general financial and strategic advisory services related to our business in return for an annual fee of $500,000, plus reimbursement of reasonable out-of-pocket expenses. This annual fee does not cover any advisory services related to acquisitions, divestitures, financings or other transactions in which we may be involved in the future. In addition, under this agreement, we will pay Wexford to-be-negotiated market-based fees approved by the conflicts committee of the board of directors of our general partner for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. This agreement has a term of two years commencing on the completion of the IPO. The agreement will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The agreement may be terminated at any time by either party upon 30 days' prior written notice. In the event we terminate the agreement, we will be obligated to pay all amounts due through the remaining term of the agreement. The services provided by Wexford under the advisory services agreement do not extend to our day-to-day business or operations. In this agreement, we indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. In the event we are dissatisfied with the services provided by Wexford, our only remedy against Wexford is to terminate the agreement. During the twelve months ended December 31, 2014, we paid $0.3 million to Wexford under the advisory services agreement.

Tax Sharing Agreement

On June 23, 2014, in connection with the closing of the IPO, we 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 the IPO. 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 no tax. However, we would nevertheless reimburse Diamondback for the tax we would have owed had the attributes not been available or used for our benefit, even though Diamondback had no cash expense for that period. During the twelve months ended December 31, 2014, we did not reimburse Wexford under the tax sharing agreement.

Shared Services Agreement

Effective September 19, 2013, we entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback. Under this agreement, Diamondback E&P LLC provides consulting and administrative services to us. We incurred a monthly charge for the services of $26,000 or other amounts that are otherwise mutually agreed to in writing between Diamondback E&P LLC and us. For the twelve months ended December 31, 2014, we incurred $156,000 for services under this agreement. This agreement was terminated at the closing of the IPO.

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

Table of Contents

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 adopted in connection with the closing of the IPO, and as a result, the transactions described above 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

Table of Contents

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 year ended December 31, 2014 and the period from inception through December 31, 2013. 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 this annual report for the year ended December 31, 2014 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 for each of the last two fiscal years (dollars in thousands):

	Year Ended December 31, 2014	Period from Inception through December 31, 2013
Audit fees(1)	$192,875	$54,434
Audit-related fees(2)	—	—
Tax fees(3)	—	—
All other fees(4)	—	—
Total	$192,875	$54,434

(1) Audit fees represent amounts billed for each of the periods presented for professional services rendered in connection with those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters.
(2) Audit-related fees represent amounts billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews.
(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.

Table of Contents

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

The Exhibit Index beginning on page E–1 of this Annual Report is incorporated herein by reference.

Table of Contents

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.

Date: February 19, 2015

VIPER ENERGY PARTNERS LP

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 19, 2015
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)	February 19, 2015
/s/ Steven E. West Steven E. West	Director	February 19, 2015
/s/ W. Wesley Perry W. Wesley Perry	Director	February 19, 2015
/s/ Michael L. Hollis Michael L. Hollis	Director	February 19, 2015
/s/ James L. Rubin James L. Rubin	Director	February 19, 2015
/s/ W. Duncan Kennedy W. Duncan Kennedy	Director	February 19, 2015
/s/ Rosalind Redfern Grover Rosalind Redfern Grover	Director	February 19, 2015

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Viper Energy Partners LP

We have audited the accompanying consolidated balance sheets of Viper Energy Partners LP (a Delaware limited partnership) and subsidiary (the “Partnership”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, unitholders’ equity and members’ equity, and cash flows for the year ended December 31, 2014 and the period from inception (September 18, 2013) to December 31, 2013. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Viper Energy Partners LP and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the year ended December 31, 2014 and the period from inception (September 18, 2013) to December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2015

Table of Contents
Viper Energy Partners LP
Consolidated Balance Sheets

	December 31, 2014	2013¬
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$15,110	$762
Restricted cash	500	—
Royalty income receivable	8,239	9,426
Other current assets	253	—
Total current assets	24,102	10,188
Oil and natural gas interests, based on the full cost method of accounting ($91,444 and $160,302 excluded from depletion at December 31, 2014 and December 31, 2013, respectively)	511,085	448,034
Accumulated depletion	(32,800)	(5,199)
	478,285	442,835
Other assets	35,015	—
Total assets	$537,402	$453,023
Liabilities and Unitholders' Equity/Members' Equity		
Current liabilities:		
Accounts payable	$6	$—
Accounts payable—related party	—	9,779
Other accrued liabilities	2,045	256
Total current liabilities	2,051	10,035
Note payable—related party	—	440,000
Total liabilities	2,051	450,035
Commitments and contingencies (Note 10)		
Members' equity	—	2,988
Unitholders' equity:		
General partner	—	—
Common units (79,708,888 units issued and outstanding as of December 31, 2014)	535,351	—
Total unitholders' equity/members' equity	535,351	2,988
Total liabilities and unitholders' equity/members' equity	$537,402	$453,023

See accompanying notes to consolidated financial statements.
¬ See Note 1 for information regarding the basis of financial statement presentation.

Table of Contents
Viper Energy Partners LP
Consolidated Statements of Operations

	Year Ended December 31, 2014¬	Period From Inception Through December 31, 2013¬
	(In thousands, except per unit amounts)	
Royalty income	$77,767	$14,987
Costs and expenses:		
Production and ad valorem taxes	5,377	972
Depletion	27,601	5,199
General and administrative expenses	3,198	—
General and administrative expenses—related party	1,174	87
Total costs and expenses	37,350	6,258
Income from operations	40,417	8,729
Other income (expense)		
Interest expense	(487)	—
Interest expense—related party, net of capitalized interest	(10,755)	(5,741)
Other income	459	—
Total other income (expense), net	(10,783)	(5,741)
Net income	$29,634	$2,988
Allocation of net income:		
Net income attributable to the period through June 22, 2014	$7,021	
Net income attributable to the period June 23, 2014 through December 31, 2014	22,613	
	$29,634	
Net income attributable to common limited partners per unit:		
Basic	$0.29	
Diluted	$0.29	
Weighted average number of limited partner units outstanding		
Basic	78,090	
Diluted	78,102	

See accompanying notes to consolidated financial statements.
¬ See Note 1 for information regarding the basis of financial statement presentation.

Table of Contents
Viper Energy Partners LP
Statement of Consolidated Unitholders’ Equity and Members’ Equity

	Limited Partners		Predecessor Members’ Equity	Total
	Common Units	Common		
		(In thousands)		
Balance at inception¬		$—	$—	$—
Net income		—	2,988	2,988
Balance at December 31, 2013¬		$—	$2,988	$2,988
Net income attributable to the period through June 22, 2014		—	7,021	7,021
Contribution of Note Payable to Equity		—	437,115	437,115
Exchange of Predecessor interests for units (Note 1)	70,450	447,124	(447,124)	—
Net proceeds from the issuance of common units	9,250	232,198	—	232,198
Distribution of net proceeds to Diamondback (Note 1)		(148,760)	—	(148,760)
Unit-based compensation	9	2,102	—	2,102
Distribution		(2,314)	—	(2,314)
Distribution to Diamondback		(17,612)	—	(17,612)
Net income attributable to the period June 23, 2014 through December 31, 2014		22,613	—	22,613
Balance at December 31, 2014	79,709	$535,351	$—	$535,351

See accompanying notes to consolidated financial statements.
¬ See Note 1 for information regarding the basis of financial statement presentation.

Table of Contents
Viper Energy Partners LP
Consolidated Statements of Cash Flows

	Year Ended December 31, 2014¬	Period From Inception Through December 31, 2013¬
	(In thousands)	
Cash flows from operating activities:		
Net income	$29,634	$2,988
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	27,601	5,199
Amortization of debt issuance costs	112	—
Unit-based compensation expense	2,102	—
Changes in operating assets and liabilities:		
Restricted cash	(500)	
Royalty income receivable	1,187	(9,426)
Other current assets	(253)	—
Accounts payable—related party	(9,779)	5,828
Accounts payable and other accrued liabilities	1,709	256
Net cash provided by operating activities	51,813	4,845
Cash flows from investing activities:		
Additions to oil and natural gas interests	(5,276)	(4,083)
Acquisition of mineral interests	(57,689)	—
Cost method investment	(33,850)	—
Net cash used in investing activities	(96,815)	(4,083)
Cash flows from financing activities		
Proceeds from borrowings on credit facility	78,000	—
Repayment on credit facility	(78,000)	—
Principal payment on subordinated note	(2,885)	—
Debt issuance costs	(1,277)	—
Proceeds from public offerings	234,546	—
Public offering costs	(2,348)	—
Distribution to Diamondback (Note 1)	(148,760)	—
Distribution to members	(19,926)	
Net cash provided by financing activities	59,350	—
Net increase in cash	14,348	762
Cash at beginning of period	762	—
Cash and cash equivalents at end of period	$15,110	$762
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$16,983	$—
Supplemental disclosure of non—cash transactions:		
Mineral interest acquired in exchange for note payable	$—	$440,000
Note payable converted to equity	$437,115	$—

Capitalized interest	$5,275	$3,951

See accompanying notes to consolidated financial statements.
¬ See Note 1 for information regarding the basis of financial statement presentation.

Table of Contents
Viper Energy Partners LP
Notes to 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 Market under the symbol “VNOM”. The Partnership was formed by Diamondback Energy, Inc., a Delaware corporation (together with its subsidiaries, “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. 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 (the “Predecessor”), a Delaware limited liability company.

Prior to the completion on June 23, 2014 of the Partnership’s initial public offering (the “IPO”) of 5,750,000 common units representing limited partner interests (which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters), Diamondback owned all of the general and limited partner interests in the Partnership. On June 23, 2014, the Partnership completed its IPO at a price to the public of $26.00 per common unit. The Partnership received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the IPO, Diamondback contributed all of the membership interests in the Predecessor to the Partnership in exchange for 70,450,000 common units, and Viper Energy Partners GP LLC (the “General Partner”), a Delaware limited liability company, maintained its non-economic general partner interest. In addition, in connection with the closing of the IPO, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.6 million and the net proceeds from the IPO. As of December 31, 2014, the Partnership had distributed $148.8 million to Diamondback as part of the IPO transactions. The contribution of the Predecessor to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and the Partnership received net proceeds of approximately $94.8 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

As of December 31, 2014, the General Partner held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 88.4% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.
Basis of Presentation
The consolidated results of operations following the completion of the IPO are presented together with the results of operations pertaining to the Predecessor. The assets of the Predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired on September 19, 2013. See Note 3—Acquisitions. The contribution of the Predecessor to the Partnership on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. The Partnership did not own any assets prior to June 17, 2014, the date of the contribution agreement by and among Diamondback, the Predecessor, the General Partner and the Partnership. Prior to the IPO, the Predecessor

was a wholly owned subsidiary of Diamondback. For periods prior to June 17, 2014, the accompanying consolidated financial statements and related notes thereto represent the financial position, results of operations, cash flows and changes in members' equity of the Predecessor and, for periods on and after June 17, 2014, the accompanying consolidated financial statements and related notes thereto represent the financial position, results of operations, cash flows and changes in partners' equity of the Partnership and its wholly owned subsidiary.

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.

Table of Contents
Viper Energy Partners LP
Notes to Financial Statements - (Continued)

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 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 and unit–based compensation.

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.

Restricted Cash

The Predecessor entered into an agreement to purchase certain overriding royalty interests and deposited $500,000 in escrow. The agreement provided that the Predecessor would have the right to terminate the agreement and receive a return of the deposit if the Predecessor in good faith asserted title defects in excess of a certain amount. The Predecessor asserted title defects in excess of the amount and requested that the escrow agent return the deposit. The seller provided the escrow agent with notice alleging the Predecessor did not timely assert title defects in good faith. The escrow agent tendered the deposit to the court subject to a judicial determination of the proper payment of the funds.

Royalty Income Receivable

Royalty income receivable consist of receivables from oil and natural gas sales delivered to purchasers. Those purchasers remit payment for production to the operator of the properties and the operator, in turn, remits payment to us. Some of the Partnership’s oil and natural gas properties are contractually operated by Diamondback. Most payments are received within three months after the production date.

Royalty income receivable are stated at amounts due from operators, net of an allowance for doubtful accounts when the Partnership believes collection is doubtful. Royalty income receivable outstanding longer than the contractual payment terms are considered past due. The Partnership determines any allowance by considering a number of factors, including the length of time royalty income receivable are past due, the Partnership’s previous loss history, the debtor’s current ability to pay its obligation to us, the condition of the general economy and the industry as a whole. The Partnership writes off specific royalty income receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. The Partnership determined that an allowance was unnecessary at both December 31, 2014 and December 31, 2013.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, receivables, payables, credit agreement and, at December 31, 2013, a note payable. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments. The note payable was carried at cost, which approximated fair value based on borrowing rates available to the Partnership for bank loans with similar terms and maturities.

Oil and Natural Gas Properties

Oil and natural gas producing activities are accounted for in accordance with 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. At December 31, 2014 and December 31, 2013, 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 $24.95 and $27.53 for the year ended December 31, 2014 and for the period from inception to December 31, 2013, respectively. Depletion for oil and gas properties was $27.6 million and $5.2 million for the year ended December 31, 2014 and for the period from inception to December 31, 2013, respectively.

Under the full cost method of accounting, the net book value of oil and natural gas properties, may not exceed a calculated "ceiling". The ceiling limitation is the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%. Estimated future net cash flows are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production. Any excess of the net book value of proved oil and natural gas properties over the ceiling is charged to expense. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2014 and for the period from inception to December 31, 2013.

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.

Capitalized Interest

The Partnership capitalizes interest on expenditures made in connection with acquisitions of unproved properties that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these properties to their intended use. Capitalized interest cannot exceed gross interest expense. During the year ended December 31, 2014 and for the period from inception to December 31, 2013, the Partnership capitalized approximately $5.3 million and $4.0 million, respectively, of interest expense.

Debt Issuance Costs

Other assets include capitalized costs of $1.2 million, net of accumulated amortization of $0.1 million as of December 31, 2014. The Partnership did not have any debt issuance costs as of December 31, 2013. The costs are associated with the Partnership's credit agreement and are being amortized over the term of the credit agreement.

Royalty Interest and Revenue Recognition

Royalty interest represents the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Revenue is recorded when title passes to the purchaser.

Royalty interest has no rights or obligations to explore, develop or operate the property and does not incur any of the costs of exploration, development and operation of the property.

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, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (70%)

and Permian Transport & Trading (15%). For the period from inception to December 31, 2013, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (59%) and Permian Transport & Trading (19%). The Partnership does not require collateral and do 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.

Table of Contents

Viper Energy Partners LP

Notes to Financial Statements - (Continued)

Investments

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over partnership operating and financial policies. This interest was acquired during the year ended December 31, 2014 and is accounted for under the cost method. Under the cost method, investments are carried at cost and are adjusted only for other than temporary declines in fair value, certain distributions and additional investments. As of December 31, 2014, the book value of this investment was $33.9 million, which is included in other assets in the accompanying consolidated balance sheets.

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 is organized as a pass-through entity for income tax purposes. As a result, the Partnership's partners are responsible for federal income taxes on their share of the Partnership's taxable income.

The Partnership is subject to the Texas margin tax. Any amounts related to operations for 2013 or for the period in 2014 prior to the closing of the IPO on June 23, 2014 will be included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the year ended December 31, 2014 or the period from inception through December 31, 2013, so no amount has been provided in the accompanying financial statements.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers". ASU 2014-09 supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2016, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Partnership is currently evaluating the impact, if any, that the adoption of ASU 2014-09 will have on the Partnership's financial position, results of operations, and liquidity.

3. ACQUISITIONS

2014 Activity

During the year ended December 31, 2014, the Partnership acquired (i) mineral interests underlying an aggregate of approximately 10,364 gross (3,261 net) acres in the Midland and Delaware basins for approximately $57.7 million and (ii) a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests for approximately $33.9 million. The equity interest is so minor that the Partnership has no influence over partnership operating and financial policies and is accounted for under the cost method.

2013 Activity

On September 19, 2013, Diamondback completed the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin for $440.0 million. As part of the closing of the acquisition, the mineral interests were conveyed from the previous owners to the Predecessor. The mineral interests entitle the Partnership to receive a 21.4% royalty interest on an average weighted basis from this acreage. The acquisition was accounted for as an acquisition of assets.

Table of Contents
Viper Energy Partners LP
Notes to Financial Statements - (Continued)

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	December 31, 2014	2013
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$419,641	$287,732
Not subject to depletion—acquisition costs		
Incurred in 2014	48,266	—
Incurred in 2013	43,178	160,302
Total not subject to depletion	91,444	160,302
Gross oil and natural gas interests	511,085	448,034
Less accumulated depletion	(32,800)	(5,199)
Oil and natural gas interests, net	$478,285	$442,835

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 to five years.

5. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2014, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of December 31, 2014.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiary.

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.

Table of Contents
Viper Energy Partners LP
Notes to Financial Statements - (Continued)

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	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

EBITDAX will be annualized beginning with the quarter ended September 30, 2014 and ending with the quarter ending March 31, 2015

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million 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.

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

Subordinated Note

Effective September 19, 2013, the Predecessor issued a subordinated note to Diamondback for the principal sum of $440.0 million for the royalty interest acquisition discussed in Note 3. In connection with the IPO, the subordinated note was converted to equity. The note bore interest at 7.625% per annum. Interest was due and payable monthly in arrears on the first business day of each calendar month. The unpaid principal balance and all accrued interest on the note were due and payable in full on October 1, 2021. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the Diamondback credit agreement. Prior to the completion of the IPO, there was $437.1 million of principal and interest outstanding under this note. The Partnership owed $9.7 million of accrued interest as of December 31, 2013, which is included in accounts payable—related party in the accompanying consolidated balance sheets.

6. RELATED PARTY TRANSACTIONS

Partnership Agreement

In connection with the closing of the IPO, the General Partner and Diamondback entered into the first amended and restated agreement of limited partnership (the "Partnership Agreement"), dated June 23, 2014.

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, 2014, the Partnership reimbursed the General Partner $0.9 million. At December 31, 2014, the Partnership owed the General Partner approximately $4,000.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement (the "Advisory Services Agreement") with Wexford Capital LP ("Wexford"), Diamondback's equity sponsor, dated as of June 23, 2014, under which Wexford provides 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 has a term of two years commencing on June 23, 2014, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Partnership terminates the Advisory Services Agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership has agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner for such services as may be provided by Wexford at the Partnership's request in connection with future acquisitions and divestitures, financings or other transactions in which the Partnership may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Partnership's day-to-day business or operations. The Partnership has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. For the year ended December 31, 2014, we incurred costs of $0.3 million, under the Advisory Services Agreement. At December 31, 2014, there were no outstanding amounts payable by the Partnership to Wexford.

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement (the "Tax Sharing Agreement") with Diamondback pursuant to which the Partnership will 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 would 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.

Shared Services Agreement

Effective September 19, 2013, the Predecessor entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback. This agreement was terminated in connection with the IPO. Under this agreement, Diamondback E&P LLC provided consulting and administrative services to the Predecessor. The Predecessor incurred a monthly charge for the services of $26,000. For the year ended December 31, 2014 and for the period from inception to December 31, 2013, the Partnership incurred costs under this agreement of $156,000 and $87,000, respectively. At December 31, 2013, the Partnership owed Diamondback E&P LLC $87,000, which is included in accounts payable—related party in the accompanying consolidated balance sheets.

7. UNIT–BASED COMPENSATION

On June 17, 2014, 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 9,144,000 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 year ended December 31, 2014, the Partnership incurred $2.1 million of unit–based compensation.

Unit Options

In accordance with the LTIP, the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the LTIP will consist of new common units of the Partnership. On June 17, 2014, the Partnership granted 2,500,000 unit options to the executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the next three anniversaries of the date of grant. In the event the fair market value per unit as of the exercise date is less than the exercise price per option unit, the vested options will automatically terminate and become null and void as of the exercise date.

The fair value of the unit options on the date of grant is expensed over the applicable vesting period. The Partnership estimates the fair values of unit options granted using a Black-Scholes option valuation model, which requires the Partnership to make several assumptions. At the time of grant the Partnership did not have a history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the unit option at the date of grant. The expected dividend yield was based upon projected performance of the Partnership.

	2014	
Grant-date fair value	$4.24	
Expected volatility	36.0	%
Expected dividend yield	5.9	%
Expected term (in years)	3.0	
Risk-free rate	0.99	%

The following table presents the unit option activity under the LTIP for the year ended December 31, 2014:

	Unit Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	—	$—		
Granted	2,500,000	$26.00		
Outstanding at December 31, 2014	2,500,000	$26.00	2.47	$—
Vested and Expected to vest at December 31, 2014	2,500,000	$26.00	2.47	$—
Exercisable at December 31, 2014	—	$—	—	$—

As of December 31, 2014, the unrecognized compensation cost related to unvested unit options was $8.7 million. Such cost is expected to be recognized over a weighted-average period of 2.5 years.

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 values 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 unit entitles the recipient one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the LTIP for the year ended December 31, 2014:

	Phantom Units		Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	—		$—
Granted	26,664		$19.51
Vested	(8,888	)	$19.51
Unvested at December 31, 2014	17,776		$19.51

The aggregate fair value of phantom units that vested during the year ended December 31, 2014 was $0.2 million. As of December 31, 2014, the unrecognized compensation cost related to unvested phantom units was $0.3 million. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

8. PARTNERS' CAPITAL AND PARTNERSHIP DISTRIBUTIONS

The Partnership has general partner and common unit partnership interests. The general partner interest is a non-economic interest and is not entitled to any cash distributions.

At December 31, 2014, the Partnership had a total of 79,708,888 common units issued and outstanding, of which 70,450,000 common units were owned by Diamondback, representing approximately 88.4% of the total Partnership units outstanding.

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

	Common Units
Diamondback Energy, Inc. ownership of common units	70,450,000
Common units issued in June 23, 2014 IPO	5,750,000
Common units issued in September 19, 2014 public offering	3,500,000
Common units vested and issued under the LTIP in 2014	8,888
Balance December 31, 2014	79,708,888

The board of directors of the General Partner has adopted a policy for the Partnership to distribute all available cash generated on a quarterly basis, beginning with the quarter ending September 30, 2014. Our first distribution, however, included available cash for the period from June 23, 2014, the date of the close of the IPO, through September 30, 2014. On November 4, 2014, the board of directors of the General Partner approved a cash distribution attributable to the period from June 23, 2014 through September 30, 2014 of $0.25 per unit, which was paid on November 28, 2014. This distribution included a total of $17.6 million distributed to Diamondback. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of the General Partner following the end of such quarter. Available cash for each quarter will generally equal 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 General Partner deems necessary or appropriate, if any.

9. EARNINGS PER UNIT

The net income per common unit on the consolidated statements of operations is based on the net income of the Partnership after the closing of its IPO on June 23, 2014 through December 31, 2014, since this is the amount of net income that is attributable to the Partnership's common units.

The Partnership's net income is allocated wholly to the common units as the General Partner does not have an economic interest. Payments made to the Partnership's unitholders are determined in relation to the cash distribution policy described in Note 8—Partners' Capital and Partnership Distributions.

Basic net income per common unit is calculated by dividing net income 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, 2014¬
Net income	$22,613
Net income per common unit, basic	$0.29

Net income per common unit, diluted	$0.29
Weighted-average common units outstanding, basic	78,090
Weighted-average common units outstanding, diluted	78,102

¬ Net income attributable to the period June 23, 2014 through December 31, 2014

10. COMMITMENTS AND CONTINGENCIES

The Partnership could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

11. SUBSEQUENT EVENTS

Table of Contents
Viper Energy Partners LP
Notes to Financial Statements - (Continued)

On February 5, 2015, the board of directors of the General Partner approved a cash distribution for the fourth quarter of 2014 of $0.25 per common unit, payable on February 27, 2015, to unitholders of record at the close of business on February 20, 2015.

12. 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, 2014	2013
	(In thousands)	
Oil and natural gas interests:		
Proved	$419,641	$287,732
Unproved	91,444	160,302
Total oil and natural gas interests	511,085	448,034
Less accumulated depletion	(32,800)	(5,199)
Net oil and natural gas interests capitalized	$478,285	$442,835

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

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(In thousands)	
Acquisition costs		
Proved	$10,879	$200,309
Unproved	46,810	247,725
Total	$57,689	$448,034

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 and natural gas. 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.

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

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(In thousands)	
Royalty income	$77,767	$14,987
Production and ad valorem taxes	(5,377)	(972)
Depletion	(27,601)	(5,199)
Results of operations from oil, natural gas and natural gas liquids	$44,789	$8,816

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2014 and 2013 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

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

The changes in estimated proved reserves are as follows:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:			
Balance at inception	—	—	—
Purchase of reserves in place	5,725,640	1,672,824	7,418,633
Extensions and discoveries	1,724,366	364,047	2,403,261
Revisions of previous estimates	(81,111)	(841,777)	1,547,955
Production	(150,815)	(19,971)	(108,264)
As of December 31, 2013	7,218,080	1,175,123	11,261,585
Purchase of reserves in place	225,217	—	346,123
Extensions and discoveries	6,937,134	1,370,291	9,831,241
Revisions of previous estimates	(693,596)	112,368	(1,795,981)
Production	(856,541)	(144,074)	(648,808)
As of December 31, 2014	12,830,294	2,513,708	18,994,160
Proved Developed Reserves:			
December 31, 2013	3,692,207	609,303	6,280,409
December 31, 2014	6,951,892	1,470,966	10,377,401

Proved Undeveloped Reserves:			
December 31, 2013	3,525,873	565,820	4,981,176
December 31, 2014	5,878,402	1,042,742	8,616,759

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.

Purchases of reserves were primarily from two acquisitions, one in the Midland Basin and one in the Delaware Basin, consisting of 11 vertical wells and two horizontal wells. Extensions are primarily the result of horizontal development of the Wolfcamp B and Lower Spraberry shales. The extensions were the result of one vertical well and 63 horizontal wells, of which 37 horizontal wells are in the proved undeveloped category. Diamondback is the operator of 49 of the 64 total wells. Revisions are primarily the result of downgrading 29 vertical wells that were classified as PUDs into the probable category as a result of changes in drilling plans such that the wells are no longer expected to be drilled within five years of when they were originally booked.

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, 2014 and 2013.

	December 31, 2014	December 31, 2013
	(In thousands)	
Future cash inflows	$1,287,730	$770,528
Future production taxes	(88,559)	(53,040)
Future state margin tax expenses	(9,014)	(5,394)
Future net cash flows	1,190,157	712,094
10% discount to reflect timing of cash flows	(636,921)	(384,848)
Standardized measure of discounted future net cash flows	$553,236	$327,246

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, 2014	December 31, 2013
	Unweighted Arithmetic Average First-Day-of-the-Month Prices	
Oil (per Bbl)	$87.33	$92.64
Natural gas (per Mcf)	$5.12	$5.03
Natural gas liquids (per Bbl)	$27.87	$38.45

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

Table of Contents
Viper Energy Partners LP
Notes to Financial Statements - (Continued)

	Year Ended December 31, 2014	Period From Inception Through December 31, 2013
	(In thousands)	
Standardized measure of discounted future net cash flows at the beginning of the period	$327,246	$—
Purchase of minerals in place	10,879	249,831
Sales of oil and natural gas, net of production costs	(72,390)	(14,015)
Extensions and discoveries	287,837	79,829
Net changes in prices and production costs	(17,266)	24,724
Revisions of previous quantity estimates	(28,270)	(19,383)
Net changes in state margin taxes	(1,650)	(586)
Accretion of discount	33,450	7,103
Net changes in timing of production and other	13,400	(257)
Standardized measure of discounted future net cash flows at the end of the period	$553,236	$327,246

13. QUARTERLY FINANCIAL DATA (Unaudited)

	2014 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit amounts)			
Royalty income	$15,853	$17,249	$22,767	$21,898
Income from operations	9,221	9,496	11,175	10,525
Net income	3,853	4,109	10,869	10,803
Net income attributable to common limited partners		941	10,869	10,803
Net income attributable to common limited partners per unit:				
Basic		$0.01	$0.14	$0.14
Diluted		$0.01	$0.14	$0.14

	Period From Inception Through December 31, 2013
	(In thousands)
Royalty income	$14,987
Income from operations	8,729

Net income	2,988

As discussed in Note 1, the results prior to the IPO reflect the results of the Predecessor.

Table of Contents

EXHIBIT INDEX

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).
4.1	Registration Rights Agreement, dated June 23, 2014, by and among 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 No. 001-36505) filed on June 23, 2014).
10.1	Senior Secured Revolving Credit Agreement, dated as of July 8, 2014, among Viper Energy Partners LP, as borrower, Wells Fargo Bank, National Association, as the administrative agent, sole book runner and lead arranger, and certain lenders from time to time 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 July 14, 2014).
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).
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). 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).
10.7+	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 (Incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q (File No. 001-36505) filed on November 6, 2014).
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.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Table of Contents

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* 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.