Viper Energy Partners LP
Form 10-Q
August 09, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2016
OR
oTRANSITION 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)

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 past 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 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 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 ý

Non-Accelerated Filer o 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
As of August 3, 2016, 86,743,124 common limited partner units of the registrant were outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and gas terms that are used in this Quarterly Report on Form 10-Q (this “report”):

Basin	A large depression on the earth’s surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
British Thermal Unit, or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
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.
Mcf	Thousand cubic feet of natural gas.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
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.
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 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.
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.

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.
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.

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GLOSSARY OF CERTAIN OTHER TERMS

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

Diamondback	Diamondback Energy, Inc., a Delaware corporation.
Exchange Act	The Securities Exchange Act of 1934, as amended.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company, and the General Partner of the Partnership.
IPO	The Partnership's initial public offering.
LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated June 23, 2014, entered into by the General Partner and Diamondback in connection with the closing of the IPO.
Predecessor	Viper Energy Partners LLC, a Delaware limited liability company, and a wholly owned subsidiary of the Partnership.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Wells Fargo	Wells Fargo Bank, National Association.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements may include statements about:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- 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 report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities laws. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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Viper Energy Partners LP
Consolidated Balance Sheets
(Unaudited)

	June 30, 2016	December 31, 2015
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$6,144	$539
Restricted cash	500	500
Royalty income receivable	7,951	9,369
Other current assets	130	476
Total current assets	14,725	10,884
Property and equipment:		
Oil and natural gas interests, based on the full cost method of accounting ($94,480 and $85,329 excluded from depletion at June 30, 2016 and December 31, 2015, respectively)	566,366	554,992
Accumulated depletion and impairment	(133,862)	(71,659)
Oil and natural gas interests, net	432,504	483,333
Other assets	35,348	35,514
Total assets	$482,577	$529,731
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable	$23	$1
Accounts payable—related party	2	4
Other accrued liabilities	1,390	82
Total current liabilities	1,415	87
Long-term debt	51,500	34,500
Total liabilities	52,915	34,587
Commitments and contingencies (Note 9)		
Unitholders' equity:		
Common units (79,743,124 units issued and outstanding as of June 30, 2016 and 79,726,006 units issued and outstanding as of December 31, 2015)	429,662	495,144
Total unitholders' equity	429,662	495,144
Total liabilities and unitholders' equity	$482,577	$529,731

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$16,836	$19,619	$30,922	$36,164
Lease bonus	196	—	304	—
Total operating income	17,032	19,619	31,226	36,164
Costs and expenses:				
Production and ad valorem taxes	1,403	1,417	2,705	2,745
Gathering and transportation	91	—	177	—
Depletion	6,584	8,949	14,734	17,850
Impairment	21,458	—	47,469	—
General and administrative expenses	1,207	1,307	2,956	2,859
Total costs and expenses	30,743	11,673	68,041	23,454
Income (loss) from operations	(13,711)	7,946	(36,815)	12,710
Other income (expense):				
Interest expense	(456)	(207)	(886)	(375)
Other income	147	306	346	792
Total other income (expense), net	(309)	99	(540)	417
Net income (loss)	$(14,020)	$8,045	$(37,355)	$13,127
Net income attributable to common limited partners per unit:				
Basic and Diluted	$(0.18)	$0.10	$(0.47)	$0.16
Weighted average number of limited partner units outstanding:				
Basic and Diluted	79,728	79,710	79,727	79,710

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Statements of Consolidated Unitholders' Equity
(Unaudited)

	Limited Partners Common Units	Common	Total
		(In thousands)	
Balance at December 31, 2014	79,709	$535,351	$535,351
Unit-based compensation	1	1,878	1,878
Distribution to public	—	(4,074)	(4,074)
Distribution to Diamondback	—	(30,997)	(30,997)
Net income	—	13,127	13,127
Balance at June 30, 2015	79,710	$515,285	$515,285
Balance at December 31, 2015	79,726	$495,144	$495,144
Unit-based compensation	17	1,930	1,930
Distribution to public	—	(3,497)	(3,497)
Distribution to Diamondback	—	(26,560)	(26,560)
Net loss	—	(37,355)	(37,355)
Balance at June 30, 2016	79,743	$429,662	$429,662

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30,	
	2016	2015
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(37,355)	$13,127
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion	14,734	17,850
Impairment	47,469	—
Amortization of debt issuance costs	186	141
Non-cash unit-based compensation	1,930	1,878
Changes in operating assets and liabilities:		
Royalty income receivable	1,418	(1,663)
Accounts payable—related party	(2)	—
Accounts payable and other accrued liabilities	1,307	(946)
Prepaid expenses and other current assets	314	(214)
Net cash provided by operating activities	30,001	30,173
Cash flows from investing activities:		
Acquisition of royalty interests	(11,319)	—
Other	—	77
Net cash provided by (used in) investing activities	(11,319)	77
Cash flows from financing activities		
Proceeds from borrowings under credit facility	17,000	—
Debt issuance costs	(20)	(301)
Distribution to partners	(30,057)	(35,071)
Net cash used in financing activities	(13,077)	(35,372)
Net increase (decrease) in cash	5,605	(5,122)
Cash and cash equivalents at beginning of period	539	15,110
Cash and cash equivalents at end of period	$6,144	$9,988
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$708	$234

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Notes to Financial Statements
(Unaudited)

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. (“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”).

As of June 30, 2016, Viper Energy Partners GP LLC (the “General Partner”), held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 88% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.

Basis of Presentation

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with GAAP. All material intercompany balances and transactions are eliminated in consolidation.

These financial statements have been prepared by the Partnership without audit, pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been omitted pursuant to such rules and regulations, although the Partnership believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Partnership’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2015, which contains a summary of the Partnership’s significant accounting policies and other disclosures.

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 interests and unit–based compensation.

New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, “Interest–Imputation of Interest”. This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount, to simplify the presentation of debt issuance costs. This update is effective for financial statements issued for fiscal years beginning after December 15, 2015. The Partnership retrospectively adopted this new standard effective January 1, 2016. Adoption of this update did not have a material impact on the Partnership’s consolidated financial statements.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, “Financial Instruments–Overall”. This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. This update will be effective for public entities for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. Entities should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The Partnership will be required to mark its cost method investment to fair value with the adoption of this update.

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, “Leases”. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Partnership is currently evaluating the impact that the adoption of this update will have on the Partnership’s financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-08, “Revenue from Contracts with Customers - Principal versus Agent Considerations (Reporting Revenue Gross versus Net)”. Under this update, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This update will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. This update allows for either full retrospective adoption, meaning this update is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning this update is applied only to the most current period presented. The Partnership is currently evaluating the impact, if any, that the adoption of this update will have on the Partnership’s financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-09, "Compensation - Stock Compensation". This update applies to all entities that issue equity-based payment awards to their employees. Under this update, there were several areas that were simplified including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years with early adoption permitted. The Partnership is currently evaluating the impact that the adoption of this update will have on the Partnership's financial position, results of operations and liquidity.

In April 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-10, “Revenue from Contracts with Customers - Identifying Performance Obligations and Licensing”. This update clarifies two principles of Accounting Standards Codification Topic 606: identifying performance obligations and the licensing implementation guidance. This standard has the same effective date as Accounting Standards Update 2016-08, the revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Partnership's financial position, results of operations and liquidity.

In May 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-12, “Revenue from Contracts with Customers - Narrow-Scope Improvements and Practical Expedients”. This update applies only to the following areas from Accounting Standards Codification Topic 606: assessing the collectability criterion and accounting for contracts that do not meet the criteria for step 1, presentation of sales taxes and other similar taxes collected from customers, noncash consideration, contract modification at transition, completed contracts at transition and technical correction. This standard has the same effective date as Accounting Standards Update 2016-08, the revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Partnership's financial position, results of operations and liquidity.

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3. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	June 30, 2016	December 31, 2015
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$471,886	$469,663
Not subject to depletion-acquisition costs		
Incurred in 2016	10,301	—
Incurred in 2015	38,790	39,693
Incurred in 2014	45,389	45,636
Total not subject to depletion	94,480	85,329
Gross oil and natural gas interests	566,366	554,992
Accumulated depletion and impairment	(133,862)	(71,659)
Oil and natural gas interests, net	$432,504	$483,333

Costs associated with unevaluated interests 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.

Under the full cost method of accounting, the Partnership is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas interests. Net capitalized costs are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Partnership's oil and natural gas revenue, (b) the cost of interests not being amortized, if any, and (c) the lower of cost or market value of unproved interests included in the cost being amortized. If the net book value exceeds the ceiling, an impairment or non-cash write down is required.

As a result of the decline in prices, the Partnership recorded a non-cash impairment for the six months ended June 30, 2016 of $47.5 million, which is included in accumulated depletion. There were no impairments recorded for the six months ended June 30, 2015. The impairment charge affected the Partnership's reported net income but did not reduce its cash flow. In addition to commodity prices, the Partnership's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

4. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a 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, 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 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 June 30, 2016, the borrowing base was set at $175.0 million and the Partnership had $51.5 million outstanding under its credit agreement. On June 21, 2016, the credit agreement was amended to add a provision requiring the borrower and the other loan parties to provide control agreements with respect to deposit accounts and securities accounts to secure obligations under the credit agreement.

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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% 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 repaid (a) to the extent that 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, purchases of margin stock, 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

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 Partnership’s 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.

5. 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, dated June 23, 2014 (the “Partnership Agreement”). 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 three and six months ended June 30, 2016 and 2015, no expenses were allocated to the Partnership by the General Partner.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement with Wexford Capital LP ("Wexford") dated as of June 23, 2014 (the "Advisory Services Agreement"), under which Wexford 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 an initial term of two years commencing on June 23, 2014, and continues 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 three months ended June 30, 2016 and 2015, the Partnership paid costs of less than $0.1 million and $0.1 million, respectively, under the Advisory Services Agreement. For the six months ended June 30, 2016 and 2015, the Partnership paid costs of less than $0.1 million and $0.3 million, respectively, under the Advisory Services Agreement.

Tax Sharing

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

Lease Bonus

During the three and six months ended June 30, 2016, Diamondback paid the Partnership $0.2 million and $0.3 million, respectively, in lease bonus payments under four leases to extend the term of the leases, reflecting an average bonus of $1,519 per acre.

6. UNIT-BASED COMPENSATION

In connection with the IPO, the board of directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan (“LTIP”), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. The LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. A total of 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 three and six months ended June 30, 2016, the Partnership incurred $1.0 million and $1.9 million, respectively, of unit–based compensation.

Phantom Units

Under the LTIP, the board of directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership’s common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting the phantom units entitle the recipient to one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the LTIP for the six months ended June 30, 2016:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2015	25,348	$ 16.89
Vested	(17,118)	$ 17.57
Unvested at June 30, 2016	8,230	$ 15.48

The aggregate fair value of phantom units that vested during the six months ended June 30, 2016 was $0.3 million. As of June 30, 2016, the unrecognized compensation cost related to unvested phantom units was $0.1 million. Such cost is expected to be recognized over a weighted-average period of 1.0 year.

7. 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 June 30, 2016, the Partnership had a total of 79,743,124 common units issued and outstanding, of which 70,450,000 common units were owned by Diamondback, representing approximately 88% of the total Partnership common units outstanding.

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

	Common Units
Balance at December 31, 2015	79,726,006
Common units vested and issued under the LTIP	17,118
Balance at June 30, 2016	79,743,124

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 ended September 30, 2014.

On February 12, 2016, the board of directors of the General Partner approved a cash distribution for the fourth quarter of 2015 of $0.228 per common unit, payable on February 26, 2016, to unitholders of record at the close of business on February 19, 2016.

On May 2, 2016, the board of directors of the General Partner approved a cash distribution for the first quarter of 2016 of $0.149 per common unit, payable on May 23, 2016, to unitholders of record at the close of business on May 16, 2016.

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.

8. EARNINGS PER UNIT

The net income per common unit on the consolidated statements of operations is based on the net income of the Partnership for the three and six months ended June 30, 2016 and 2015, 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 7—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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands, except per unit amounts)			
Net income (loss) attributable to the period	$(14,028)	$8,045	$(37,351)	$13,127
Net income per common unit, basic	$(0.18)	$0.10	$(0.47)	$0.16
Net income per common unit, diluted	$(0.18)	$0.10	$(0.47)	$0.16
Weighted-average common units outstanding, basic	79,728	79,710	79,727	79,710
Weighted-average common units outstanding, diluted	79,728	79,710	79,727	79,710

For the three and six months ended June 30, 2016, there were 1,216,841 shares and 1,625,106 shares, respectively, that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods.

9. 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.

Litigation

The Partnership filed an action in October 2014 to recover $0.5 million held in escrow in connection with a purchase and sale agreement. The escrow agent interpleaded the funds, and the other parties to the agreement have filed a counterclaim to recover the escrow. Both sides also seek recovery of their attorneys' fees. The case is expected to be scheduled for trial in the third quarter of 2016. It is not possible to predict the outcome with reasonable certainty, but the Partnership does not believe that an adverse outcome would have a material adverse effect on the Partnership's financial statements and has not included a loss contingency reserve for this matter.

10. SUBSEQUENT EVENTS

Cash Distribution

On July 21, 2016, the board of directors of the General Partner approved a cash distribution for the second quarter of 2016 of $0.189 per common unit, payable on August 22, 2016, to unitholders of record at the close of business on August 15, 2016.

August 2016 Public Offering
On August 1, 2016, the Partnership completed an underwritten public offering of 7,000,000 common units. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at $15.60 per unit, which is the price

per common unit paid by the underwriter to the Partnership. The Partnership received net proceeds from this offering of approximately $109.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, which the Partnership intends to use to fund the purchase price for the pending acquisition described below under the heading “-Pending Acquisition” and repay outstanding borrowings under its revolving credit facility.
Recent Acquisitions

On July 22, 2016, the Partnership acquired from an unrelated third party mineral interests underlying an additional 7,487 gross (601 net royalty) acres in the Midland Basin, with approximately 300 BOE/d of estimated August 2016 net production, for $79.2 million, subject to certain post-closing adjustments.

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In July 2016, the Partnership also acquired from unrelated third party sellers mineral interests underlying an additional 9,281 gross (152 net royalty) acres in the Permian Basin for an aggregate of $11.7 million, subject to post-closing adjustments.

The purchase price for each of the above described recent acquisitions was primarily funded with borrowings under the Partnership's revolving credit facility. As of July 22, 2016, the Partnership had $132.5 million in borrowings outstanding under the Partnership's credit agreement, with a variable interest rate of 3.95%.

Pending Acquisition

On July 22, 2016, the Partnership entered into a purchase agreement with an unrelated third party to acquire mineral interests in 650 gross (142 net royalty) acres in the Delaware Basin, with approximately 200 BOE/d of estimated August 2016 net production, for approximately $31.4 million, subject to certain adjustments (the "Pending Acquisition"). The Partnership intends to use a portion of the net proceeds of its August 2016 public offering of common units to fund the purchase price of the Pending Acquisition. The Pending Acquisition is expected to close in August 2016; however, the transaction remains subject to completion of due diligence and satisfaction of other closing conditions, and there can be no assurance that it will be completed as planned or at all.

ITEM 2.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015. 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 "Part II. 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 June 30, 2016, our general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 88% limited partner interest in us. Diamondback also owns and controls our general partner.

On August 1, 2016, we completed an underwritten public offering of 7,000,000 common units. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at $15.60 per unit, which is the price per common unit paid by the underwriter to us. Following the August 2016 public offering, Diamondback had an approximate 84% limited partner interest in us. We received net proceeds from this offering of approximately $109.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we intend to use to fund the purchase price for the pending acquisition described below under the heading "–Production and Operational Update–Pending Acquisition" and repay outstanding borrowings under our revolving credit facility.
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 interests principally located in the Permian Basin of West Texas.

Sources of Our Income

Our income is derived from royalty payments we receive from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. Royalty payments may vary significantly from period to period as a result of commodity prices, production mix and volumes of production sold by our operators. For the three months ended June 30, 2016, our royalty income was derived 92% from oil sales, 5% from natural gas liquid sales and 3% from natural gas sales and for the three months ended June 30, 2015, our royalty income was derived 93% from oil sales, 4% from natural gas liquid sales and 3% from natural gas sales. For the six months ended June 30, 2016, our royalty income was derived 92% from oil sales, 4% from natural gas liquid sales and 4% from natural gas sales and for the six months ended June 30, 2015, our royalty income was derived 94% from oil sales, 3% from natural gas liquid sales and 3% from natural gas sales. As a result, our income is more sensitive to fluctuations in oil prices than is it to fluctuations in natural gas liquids or natural gas prices. Our income may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile.

During 2015, West Texas Intermediate posted prices ranged from $34.55 to $61.36 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.63 to $3.32 per MMBtu. On June 30, 2016, the West Texas Intermediate posted price for crude oil was $48.27 per Bbl and the Henry Hub spot market price of natural gas was $2.94 per MMBtu. Lower prices may not only decrease our income, but also potentially the amount of oil and natural gas that our operators can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be determined at the discretion of our lenders.

As a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves, we recorded a non-cash impairment to the book value of our oil and natural gas interests for the six months ended June 30, 2016 of $47.5 million.

Production and Operational Update

Our average daily production during the second quarter of 2016 was 5,380 BOE/d (76% oil), and our operators received an average of $41.73 per Bbl of oil, $13.03 per Bbl of natural gas liquids and $1.56 per Mcf of natural gas, for an average realized price of $34.39 per BOE.

During the second quarter of 2016, the operators of our Spanish Trail mineral interests brought online eight gross horizontal wells, consisting of six Lower Spraberry and two Wolfcamp A completions and built an inventory of 35 drilled but uncompleted wells as a result of low commodity prices during the first half of 2016. As of June 30, 2016, there were 432 vertical wells and 125 horizontal wells producing on our acreage. In addition, there were 40 horizontal wells in various stages of completion.

We declared a cash dividend for the second quarter of 2016 of $0.189 per common unit, payable on August 22, 2016, to unitholders of record at the close of business on August 15, 2016.

Recent Acquisitions

On July 22, 2016, we acquired from an unrelated third party mineral interests underlying an additional 7,487 gross (601 net royalty) acres in the Midland Basin, with approximately 300 BOE/d of estimated August 2016 net production, for $79.2 million, subject to certain post-closing adjustments. Estimated net proved reserves, based on internal estimates as of July 1, 2016, were approximately 1.0 MMBOE. Our internal estimate of net proved reserves is based on our analysis of production data provided by the seller, as well as geologic and other data, and has not been reviewed by our independent petroleum engineers. We believe this acreage is prospective in the Wolfcamp A, Wolfcamp B, Lower Spraberry and Middle Spraberry horizons.

In addition, since the end of the first quarter of 2016, we acquired from unrelated third party sellers mineral interests underlying an additional 13,182 gross (325 net royalty) acres in the Permian Basin for an aggregate of $20.8 million, subject to post-closing adjustments. As a result, as of July 22, 2016, our assets included mineral interests underlying 69,225 gross (5,215 net royalty) acres primarily in the Permian Basin.

The purchase price for each of the above described recent acquisitions was primarily funded with borrowings under our revolving credit facility.

Pending Acquisition

On July 22, 2016, we entered into a purchase agreement with an unrelated third party to acquire mineral interests in 650 gross (142 net royalty) acres in the Delaware Basin, with approximately 200 BOE/d of estimated August 2016 net production, for approximately $31.4 million, subject to certain adjustments (which transaction we refer to as the Pending Acquisition). Estimated net proved reserves, based on internal estimates as of August 1, 2016, were approximately 0.6 MMBOE. Our internal estimate of net proved reserves is based on our analysis of production data provided by the seller, as well as geologic and other data, and has not been reviewed by our independent petroleum engineers. We believe this acreage is prospective in the Wolfcamp, Bone Springs, Avalon Shale and Brushy Canyon horizons. We intend to use a portion of the net proceeds of our August 2016 public offering of common units to fund the purchase price of the Pending Acquisition. The Pending Acquisition is expected to close in August 2016; however, the transaction remains subject to completion of due diligence and satisfaction of other closing conditions, and there can be no assurance that it will be completed as planned or at all. Assuming the Pending Acquisition is completed in its entirety, our assets would include mineral interests underlying 69,875 gross (5,357 net royalty) acres.

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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 interests.

General and Administrative

In connection with the closing of the IPO, our general partner and Diamondback entered into the first amended and restated agreement of limited partnership, dated as of June 23, 2014. The partnership agreement requires us to reimburse our general partner for all direct and indirect expenses incurred or paid on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. The partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us.

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.

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 interests 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 the period in 2014 prior to the closing of the IPO on June 23, 2014 was included in Diamondback’s unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the six months ended June 30, 2016 or 2015.

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Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(unaudited, in thousands, except production data)			
Operating Results:				
Operating income:				
Royalty income	$16,836	$19,619	$30,922	$36,164
Lease bonus	196	—	304	—
Total operating income	17,032	19,619	31,226	36,164
Costs and expenses:				
Production and ad valorem taxes	1,403	1,417	2,705	2,745
Gathering and transportation	91	—	177	—
Depletion	6,584	8,949	14,734	17,850
Impairment	21,458	—	47,469	—
General and administrative expenses	1,207	1,307	2,956	2,859
Total costs and expenses	30,743	11,673	68,041	23,454
Income (loss) from operations	(13,711)	7,946	(36,815)	12,710
Other income (expense)				
Interest expense	(456)	(207)	(886)	(375)
Other income	147	306	346	792
Total other income (expense), net	(309)	99	(540)	417
Net income (loss)	$(14,020)	$8,045	$(37,355)	$13,127
Production Data:				
Oil (Bbls)	371,730	342,869	805,271	694,236
Natural gas (Mcf)	345,432	239,470	693,715	459,122
Natural gas liquids (Bbls)	60,258	56,956	129,361	104,956
Combined volumes (BOE)	489,560	439,737	1,050,251	875,712
Daily combined volumes (BOE/d)	5,380	4,832	5,771	4,838
% Oil	76%	78%	77%	79%

Comparison of the Three Months Ended June 30, 2016 and 2015

Royalty Income

Our royalty income for the three months ended June 30, 2016 and 2015 was $16.8 million and $19.6 million, respectively.

Our income is 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 $41.73 per Bbl of oil, $13.03 per Bbl of natural gas liquids and $1.56 per Mcf of natural gas for the volumes sold for the three months ended June 30, 2016. Our operators received an average of $53.40 per Bbl of oil, $13.99 per Bbl of natural gas liquids and $2.15 per Mcf of natural gas for the volumes sold for the three months ended June 30, 2015. The decrease in average prices received during the three months ended June 30, 2016 was partially offset by an 11.3% increase in combined volumes sold by our operators as compared to the three months ended June 30, 2015.

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	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (11.67)	371,730	$ (4,337)
Natural gas liquids	(0.96)	60,258	(58)
Natural gas	(0.59)	345,432	(204)
Total income due to change in price			$ (4,599)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	28,861	$ 53.40	$ 1,542
Natural gas liquids	3,302	13.99	46
Natural gas	105,962	2.15	228
Total income due to change in production volumes			1,816
Total change in income			$ (2,783)

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Impairment

During the three months ended June 30, 2016, we recorded an impairment of oil and natural gas interests of $21.5 million as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves.

General and Administrative Expenses

The general and administrative expenses primarily reflect costs associated with us being a publicly traded limited partnership, unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the three months ended June 30, 2016 and 2015, we incurred general and administrative expenses of $1.2 million and $1.3 million, respectively.

Net Interest Expense

The net interest expense for the three months ended June 30, 2016 and 2015 reflects the interest incurred under our credit agreement. Net interest expense for the three months ended June 30, 2016 and 2015 was $0.5 million and $0.2 million, respectively.

Comparison of the Six Months Ended June 30, 2016 and 2015

Royalty Income

Our royalty income for the six months ended June 30, 2016 and 2015 was $30.9 million and $36.2 million, respectively.

Our income is 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 $35.31 per Bbl of oil, $10.30 per Bbl of natural gas liquids and $1.66 per Mcf of natural gas for the volumes sold for the six months ended June 30, 2016. Our operators received an average of $48.75 per Bbl of oil, $11.81 per Bbl of natural gas liquids and $2.36 per Mcf of natural gas for the volumes sold for the six months ended June 30, 2015. The decrease in average prices received during the six months ended June 30, 2016 was partially offset by a 19.9% increase in combined volumes sold by our operators as compared to the six months ended June 30, 2015.

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	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (13.44)	805,271	$ (10,819)
Natural gas liquids	(1.51)	129,361	(195)
Natural gas	(0.70)	693,715	(486)
Total income due to change in price			$ (11,500)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	111,035	$ 48.75	$ 5,416
Natural gas liquids	24,405	11.81	288
Natural gas	234,593	2.36	554
Total income due to change in production volumes			6,258
Total change in income			$ (5,242)

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Impairment

During the six months ended June 30, 2016, we recorded an impairment of oil and natural gas interests of $47.5 million as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves.

General and Administrative Expenses

The general and administrative expenses primarily reflect costs associated with us being a publicly traded limited partnership, unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the six months ended June 30, 2016 and 2015, we incurred general and administrative expenses of $3.0 million and $2.9 million, respectively.

Net Interest Expense

The net interest expense for the six months ended June 30, 2016 and 2015 reflects the interest incurred under our credit agreement. Net interest expense for the six months ended June 30, 2016 and 2015 was $0.9 million and $0.4 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, non-cash unit-based compensation, depletion expense and impairment 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.

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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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Net income (loss)	$(14,020)	$8,045	$(37,355)	$13,127
Interest expense	456	207	886	375
Non-cash unit-based compensation expense	957	939	1,930	1,878
Depletion	6,584	8,949	14,734	17,850
Impairment	21,458	—	47,469	—
Adjusted EBITDA	$15,435	$18,140	$27,664	$33,230

Liquidity and Capital Resources

Overview

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

Our partnership agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it is 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.

On July 21, 2016, the board of directors of the General Partner approved a cash distribution for the second quarter of 2016 of $0.189 per common unit, payable on August 22, 2016, to unitholders of record at the close of business on August 15, 2016.

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.

August 2016 Public Offering

On August 1, 2016, we completed an underwritten public offering of 7,000,000 common units. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at the price per common unit paid by the underwriter to us. We received net proceeds from this offering of approximately $109.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we intend to use to fund the purchase price for the pending acquisition described above under the heading "-Pending Acquisition" and repay outstanding borrowings under our revolving credit facility.

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. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. On November 13, 2015, the borrowing base was increased from $175.0 million to $200.0 million. In connection with our spring 2016 redetermination, our borrowing base was set at $175.0 million due to a decline in pricing. As of June 30, 2016, we had $51.5 million in outstanding borrowings under the credit agreement, with a weighted average interest rate of 2.20%. As of July 22, 2016, we had $132.5 million in borrowings outstanding under the credit agreement, with a variable interest rate of 3.95%. The outstanding borrowings under the credit agreement were used to fund acquisitions. On August 5, 2016, we used a portion of the net proceeds from our August 2016 public offering to repay $78.0 million of the borrowings outstanding under our revolving credit facility.

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 repaid (a) to the extent that 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 assets and our subsidiaries' assets.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, purchases of margin stock, 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

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 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.

Cash Flows

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

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Cash Flow Data:		
Net cash flows provided by operating activities	$30,001	$30,173
Net cash flows (used in) provided by investing activities	(11,319)	77
Net cash flows used in financing activities	(13,077)	(35,372)
Net increase (decrease) in cash	$5,605	$(5,122)

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which are the volatility of prices for oil and natural gas and the volume of oil and natural gas sold by our producers. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

Investing Activities

Net cash used in investing activities was $11.3 million during the six months ended June 30, 2016 related to acquisitions of royalty interests.

Financing Activities

Net cash used in financing activities was $13.1 million and $35.4 million during the six months ended June 30, 2016 and 2015, respectively, primarily related to our distributions to our unitholders for our first quarter 2016 and 2015 distributions, after giving effect to $17.0 million of proceeds from borrowings under our credit facility for the six months ended June 30, 2016.

Contractual Obligations

There were no material changes in our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Critical Accounting Policies

There have been no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 3. 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 two years, 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 income in producing oil and natural gas interests and receivables with several significant purchasers. For the six months ended June 30, 2016, two purchasers accounted for more than 10% of our royalty income: Shell Trading (US) Company (65%) and RSP Permian LLC (27%). For the six months ended June 30, 2015, two purchasers accounted for more than 10% of our royalty income: Shell Trading (US) Company (71%) and RSP Permian LLC (23%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

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 0.50% to 1.50% in the case of the alternative base rate

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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 June 30, 2016, we had $51.5 million in outstanding borrowings with a weighted average rate of 2.20%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.5 million based on the $51.5 million outstanding in the aggregate under our credit agreement on June 30, 2016.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of the Chief Executive Officer and Chief Financial Officer of our general partner, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer of our general partner, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of June 30, 2016, 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 June 30, 2016, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Note 9. “Commitments and Contingencies–Litigation” to our financial statements.

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed in this report and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10–K for the year ended December 31, 2015 and in subsequent filings we make with the SEC. There have been no material changes in our risk factors from those described in our Annual Report on Form 10–K for the year ended December 31, 2015.

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ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Viper Energy Partners LP (Incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement on Form S-1 (File No. 333-195769) filed on May 7, 2014).
3.2	First Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP (Incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
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	Third Amendment, dated as of June 21, 2016, to the Credit Agreement, dated as of July 8, 2014, by and among Viper Energy Partners LP, as borrower, Viper Energy Partners LLC, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed June 27, 2016).
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.
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.

* Filed herewith.

** The certifications attached as Exhibit 32.1 accompany this Quarterly Report on Form 10-Q 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.

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SIGNATURES

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

		VIPER ENERGY PARTNERS LP	
		By:	VIPER ENERGY PARTNERS GP LLC its General Partner
Date:	August 9, 2016	By:	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer
Date:	August 9, 2016	By:	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer