Viper Energy Partners LP
Form 10-Q
November 06, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 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	79701
(Address of Principal Executive Offices)	(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	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
As of October 29, 2014, 79,700,000 common limited partner units of the registrant were outstanding.

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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 of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or 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 quarterly 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 quarterly report on Form 10–Q and detailed in our final prospectus dated June 17, 2014 and filed with the Securities and Exchange Commission, or SEC, pursuant to Rule 424(b) under the Securities Act of 1933, or the Securities Act, on June 18, 2014, 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;
- the ability of our operators to keep pace with technological advancements; and

All forward-looking statements speak only as of the date of this quarterly 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 quarterly 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)

	September 30, 2014	December 31, 2013¬
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$13,504	$762
Royalty income receivable	9,965	9,426
Other current assets	567	—
Total current assets	24,036	10,188
Oil and natural gas interests, based on the full cost method of accounting ($157,249 and $160,302 excluded from depletion at September 30, 2014 and December 31, 2013, respectively)	510,997	448,034
Accumulated depletion	(24,801)	(5,199)
	486,196	442,835
Other assets	35,076	—
Total assets	$545,308	$453,023
Liabilities and Unitholders’ Equity/Members’ Equity		
Current liabilities:		
Accounts payable—related party	$—	$9,779
Other accrued liabilities	1,789	256
Total current liabilities	1,789	10,035
Note payable—related party	—	440,000
Total liabilities	1,789	450,035
Commitments and contingencies (Note 11)		
Members’ equity	—	2,988
Unitholders’ equity:		
General partner	—	—
Common units (79,700,000 units issued and outstanding as of September 30, 2014)	543,519	—
Total unitholders’ equity/members’ equity	543,519	2,988
Total liabilities and unitholders’ equity/members’ equity	$545,308	$453,023

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

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Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014¬	Period From Inception (September 18, 2013) Through December 31, 2013¬
	(In thousands, except per unit amounts)		
Royalty income	$22,767	$55,869	$14,987
Costs and expenses:			
Production and ad valorem taxes	1,478	3,791	972
Depletion	7,971	19,602	5,199
General and administrative expenses	1,250	1,535	—
General and administrative expenses—related party	893	1,049	87
Total costs and expenses	11,592	25,977	6,258
Income from operations	11,175	29,892	8,729
Other income (expense)			
Interest expense	(317)	(317)	—
Interest expense—related party, net of capitalized interest	—	(10,755)	(5,741)
Other income	11	11	—
Total other income (expense), net	(306)	(11,061)	(5,741)
Net income	$10,869	$18,831	$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 September 30, 2014		11,810	
		$18,831	
Net income attributable to common limited partners per unit:			
Basic	$0.14	$0.15	
Diluted	$0.14	$0.15	
Weighted average number of limited partner units outstanding			
Basic	76,618	76,589	
Diluted	77,235	76,659	

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

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Viper Energy Partners LP
Statement of Consolidated Unitholders’ Equity and Members’ Equity
(Unaudited)

	Limited Partners		
	Common	Predecessor Members’ Equity	Total
	(In thousands)		
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)	447,124	(447,124)	—
Net proceeds from the issuance of common units	232,334	—	232,334
Distribution to Diamondback (Note 1)	(148,760)	—	(148,760)
Unit-based compensation	1,011	—	1,011
Net income attributable to the period June 23, 2014 through September 30, 2014	11,810	—	11,810
Balance at September 30, 2014	$543,519	$—	$543,519

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

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

	Nine Months Ended September 30, 2014¬	Period From Inception (September 18, 2013) Through December 31, 2013¬
	(In thousands)	
Cash flows from operating activities:		
Net income	$18,831	$2,988
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	19,602	5,199
Amortization of debt issuance costs	47	—
Unit-based compensation expense	1,011	—
Changes in operating assets and liabilities:		
Royalty income receivable	(539)	(9,426)
Other current assets	(567)	—
Accounts payable—related party	(9,779)	5,828
Accounts payable and other accrued liabilities	1,027	256
Net cash provided by operating activities	29,633	4,845
Cash flows from investing activities:		
Additions to oil and natural gas interests	(5,275)	(4,083)
Acquisition of mineral interests	(57,688)	—
Cost method investment	(33,851)	—
Net cash used in investing activities	(96,814)	(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	(1,272)	—
Proceeds from public offerings	234,546	—
Public offering costs	(1,706)	—
Distribution to Diamondback (Note 1)	(148,760)	—
Net cash provided by financing activities	79,923	—
Net increase in cash	12,742	762
Cash at beginning of period	762	—
Cash and cash equivalents at end of period	$13,504	$762
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$16,766	$—
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.

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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., 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, Diamondback owned all of the general and limited partner interests in the Partnership. On June 23, 2014, the Partnership completed its 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 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 September 30, 2014, the Partnership had distributed $148.8 million to Diamondback. 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 $95.1 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

As of September 30, 2014, 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 consolidated results of operations following the completion of the IPO are presented together with the results of operations pertaining to our 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 that are generally accepted in the United States. All material intercompany balances and transactions are eliminated in consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

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 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 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.

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 our 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 we believe collection is doubtful. Royalty income receivable outstanding longer than the contractual payment terms are considered past due. We determine any allowance by considering a number of factors, including the length of time royalty income receivable are past due, our 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. We write off specific royalty income receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. We determined that an allowance was unnecessary at both September 30, 2014 and December 31, 2013.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, receivables, payables 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 us 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

September 30, 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 $25.57, $27.14 and $27.53 for the three months and nine months ended September 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, respectively. Depletion for oil and gas properties was $7,971,000, $19,602,000 and $5,199,000 for the three months and nine months ended September 30, 2014 and for the period from inception (September 18, 2013) 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 three months and nine months ended September 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013.

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.

Capitalized Interest

We capitalize 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 three months ended September 30, 2014, we did not capitalize any interest expense. During the nine months ended September 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, we capitalized approximately $5,275,000 and $3,951,000, respectively, of interest expense.

Debt Issuance Costs

Other assets include capitalized costs of $1,225,000, net of accumulated amortization of $47,000 as of September 30, 2014. We did not have any debt issuance costs as of December 31, 2013. The costs are associated with our secured revolving credit facility and are being amortized over the term of the facility.

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

We are subject to risk resulting from the concentration of our royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the nine months ended September 30, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (71%); and Permian Transport & Trading (12%). For the period from inception (September 18, 2013) 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.

Investments

We have an equity interest in a limited partnership that is so minor that we have no influence over partnership operating and financial polices. This interest was acquired during the three months ended September 30, 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 September 30, 2014, the book value of this investment was $33.9 million, which is included in other assets in the accompanying 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 8—Unit–Based Compensation.

Income Taxes

The Partnership is 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 nine months ended September 30, 2014 or the period from inception (September 18, 2013) through December 31, 2013, so no amount has been provided in the accompanying financial statements of our Predecessor.

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 accounting principles generally accepted in the United States ("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.

3. ACQUISITIONS

2014 Activity

During the nine months ended September 30, 2014, the Partnership acquired (i) mineral interests underlying an aggregate of approximately 10,565 gross (3,461) 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 we have no influence over partnership operating and financial polices 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 us to receive a 21.4% royalty interest on an acreage weighted basis from this acreage. The acquisition was accounted for as an acquisition of assets.

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4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	September 30, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$353,748	$287,732
Not subject to depletion—acquisition costs		
Incurred in 2014	52,085	—
Incurred in 2013	105,164	160,302
Total not subject to depletion	157,249	160,302
Gross oil and natural gas interests	510,997	448,034
Less accumulated depletion	(24,801)	(5,199)
Oil and natural gas interests, net	$486,196	$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 our unevaluated costs into the amortization base is expected to be completed within three to five years.

5. DEBT

Credit Facility-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 September 30, 2014, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of September 30, 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 subsidiaries.

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 the Partnership's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. 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 revolving credit facility. Prior to the completion of the IPO, there was $437.1 million of principal and interest outstanding under this note. We owed $9.7 million of accrued interest as of December 31, 2013, which is included in accounts payable—related party in the accompanying balance sheets.

6. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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Viper Energy Partners LP
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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis
The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements.

	September 30, 2014	
	Carrying Amount	Fair Value
	(in thousands)	
Debt:		
Revolving credit facility	$—	$—

We had no outstanding borrowings as of September 30, 2014. The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

7. 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 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 three months and nine months ended September 30, 2014, we reimbursed our General Partner $750,000 and $750,000, respectively. At September 30, 2014, we owed our General Partner no amounts.

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, dated as of June 23, 2014, 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 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 we terminate such agreement, we are obligated to pay all amounts due through the remaining term. In addition, we have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict 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. The services provided by Wexford under the Advisory Services Agreement do not extend to our day-to-day business or operations. We have 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 and nine months ended September 30, 2014, we incurred costs of $143,000 and $143,000, respectively, under the Advisory Services Agreement. At September 30, 2014, we owed Wexford no amounts.

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 we will 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 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 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.

Shared service agreements

Effective September 19, 2013, the Predecessor entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. 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 nine months ended September 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, we 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 balance sheets.

8. 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 three months and nine months ended September 30, 2014, we incurred $883,000 and $1,011,000, respectively 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, we granted 2,500,000 unit options to our 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 then 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. We estimate the fair values of unit options granted using a Black-Scholes option valuation model, which requires us to make several assumptions. At the time of grant we 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	%

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Viper Energy Partners LP
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The following table presents the unit option activity under the LTIP for the nine months ended September 30, 2014:

		Weighted Average		
	Unit Options	Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	—	$—		
Granted	2,500,000	$26.00		
Outstanding at September 30, 2014	2,500,000	$26.00	2.72	$—
Vested and Expected to vest at September 30, 2014	2,500,000	$26.00	2.72	$—
Exercisable at September 30, 2014	—	$—	—	$—

As of September 30, 2014, the unrecognized compensation cost related to unvested unit options was $9,589,000. Such cost is expected to be recognized over a weighted-average period of 2.7 years.

9. 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 September 30, 2014, the Partnership had a total of 79,700,000 common units issued and outstanding, of which 70,450,000 common units were owned by Diamondback, representing approximately 88% of the total Partnership units outstanding.

The following table summarizes changes in the number of our common units:

	Common
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
Balance September 30, 2014	79,700,000

The board of directors of our 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, will include 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 the General Parter 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.

10. 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 September 30, 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.

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Viper Energy Partners LP
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Basic and diluted net income per common unit is calculated by dividing net income by the weighted-average number of common units outstanding during the period.

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014¬
	(In thousands, except per unit amounts)	
Net income	$10,869	$11,810
Net income per common unit, basic	$0.14	$0.15
Net income per common unit, diluted	$0.14	$0.15
Weighted-average common units outstanding, basic	76,618	76,588
Weighted-average common units outstanding, diluted	77,235	76,659

¬ Net income attributable to the period June 23, 2014 through September 30, 2014

11. COMMITMENTS AND CONTINGENCIES

We 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.

12. SUBSEQUENT EVENTS

On November 4, 2014, the Board of Directors of our General Partner approved a cash distribution attributable to the period from June 23, 2014 through September 30, 2014 of $0.25 per unit, payable on November 28, 2014, to unitholders of record at the close of business on November 21, 2014.

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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 Quarterly Report on Form 10–Q as well as our audited consolidated financial statements and notes thereto included in our final prospectus dated June 17, 2014 and filed with the SEC pursuant to Rule 424(b) under the Securities Act, on June 18, 2014. 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 September 30, 2014, 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 also owns and controls the General Partner.

Recent Developments

Public Offerings

Prior to the completion on June 23, 2014 of our IPO of 5,750,000 common units representing limited partner interests, Diamondback owned all of the general and limited partner interests in the Partnership. 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 the Predecessor to the Partnership in exchange for 70,450,000 common units. Furthermore, in exchange for the contribution of the Predecessor, the Partnership 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. The Partnership distributed $148.8 million to Diamondback as of September 30, 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, 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 $95.1 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 each of the three months and the nine months ended September 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquid sales and 3% from natural gas sales. For the period from inception (September 18, 2013) 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 2013, West Texas Intermediate posted prices ranged from $86.65 to $110.62 per Bbl and the Henry Hub spot market price of natural gas ranged from $3.08 to $4.52 per MMBtu. On December 31, 2013, the West Texas Intermediate posted price for crude oil was $98.17 per Bbl and the Henry Hub spot market price of natural gas was $4.31 per MMBtu. Over the past several months, oil prices have declined from over $105.00 per Bbl in June 2014 to below $80.00 per Bbl in October 2014 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 revolving credit facility, which may be determined at the discretion of our lenders.

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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 properties.

General and Administrative

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 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.

In connection with the closing of the IPO, we and our General Partner entered into an advisory services agreement with Wexford, our advisory services agreement, pursuant to which Wexford provides general financial and strategic advisory services to us and our General Partner in exchange for a $500,000 annual fee and certain expense reimbursement.

The 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 Energy, Inc., 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

The Partnership is 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 nine months ended September 30, 2014 or the period from inception (September 18, 2013) 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 The Predecessor

The Partnership was formed on February 27, 2014 and did not own any assets prior to the contribution of the Predecessor to the Partnership on June 17, 2014. 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, to our accompanying unaudited consolidated financial statements. 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. Therefore, the financial and operating data below represent the 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 the Partnership’s operations.

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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 was converted to equity; therefore, we no longer have the note payable and related interest expense.
- 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 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 redetermined 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 September 30, 2014, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of September 30, 2014.

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.
- On June 17, 2014, under the Long Term Incentive Plan, or LTIP, adopted in connection with the IPO, the Partnership granted awards of an aggregate of 2,500,000 unit options under the LTIP to executive officers of the General Partner.
- 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 $500,000 annual fee and certain expense reimbursement.
- In connection with the closing of the IPO, we entered into a tax sharing agreement with Diamondback pursuant to which we will 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 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 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.

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

	Three Months Ended September 30, 2014		Nine Months Ended September 30, 2014		Period From Inception (September 18, 2013) Through December 31, 2013	
	(unaudited, in thousands, except production data)					
Operating Results:						
Royalty income	$22,767		$55,869		$14,987	
Costs and expenses:						
Production and ad valorem taxes	1,478		3,791		972	
Depletion	7,971		19,602		5,199	
General and administrative expenses	1,250		1,535		—	
General and administrative expenses—related party	893		1,049		87	
Total costs and expenses	11,592		25,977		6,258	
Income from operations	11,175		29,892		8,729	
Other income (expense)						
Interest expense	(317	)	(317	)	—	
Interest expense—related party, net of capitalized interest	—		(10,755	)	(5,741	)
Other income	11		11		—	
Total other income (expense), net	(306	)	(11,061	)	(5,741	)
Net income	$10,869		$18,831		$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 September 30, 2014			11,810			
			$18,831			
Production Data:						
Oil (Bbls)	233,971		553,675		150,815	
Natural gas (Mcf)	199,877		438,909		108,264	
Natural gas liquids (Bbls)	42,410		99,213		19,971	
Combined volumes (BOE)	309,694		726,040		188,830	
Daily combined volumes (BOE/d)	3,366		2,659		1,798	
% Oil	75	%	76	%	80	%

Royalty Income

Our royalty income for the three months and nine months ended September 30, 2014 was $22,767,000 and $55,869,000, respectively. For the period from inception (September 18, 2013) to December 31, 2013 our royalty income was $14,987,000.

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 $88.69 and $92.06 per Bbl of oil, $28.37 and $30.17 per Bbl of natural gas liquids and $4.07 and $4.34 per Mcf of natural gas for the volumes sold for the three months and nine months ended September 30, 2014, respectively. Our operators received an average of $92.07 per Bbl of oil, $35.32 per Bbl of natural gas liquids and $3.67 per Mcf of natural gas for the volumes sold for the period from inception (September 18, 2013) to December 31, 2013.

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General and Administrative Expenses
The general and administrative expenses primarily reflect the amounts reimbursed to our General Partner under our Partnership Agreement, unit-based compensation and amounts incurred under our advisory services agreement. For the three months and nine months ended September 30, 2014, we incurred general and administrative expenses of $2,143,000 and $2,584,000, respectively. For the period from inception (September 18, 2013) to December 31, 2013, we incurred general and administrative expenses of $87,000.

Net Interest Expense
The net interest expense for the three months ended September 30, 2014 reflects the interest incurred under the secured revolving credit agreement. The net interest expense for the nine months ended September 30, 2014 and for the period from inception (September 18, 2013) through December 31, 2013 primarily relates to interest incurred under the subordinate note of the Predecessor. Net interest expense for the three months and nine months ended September 30, 2014 was $317,000 and $11,072,000, respectively. For the period from inception (September 18, 2013) through December 31, 2013 net interest expense was $5,741,000.

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 United States' generally accepted accounting principles, or 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.

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014	Period From Inception (September 18, 2013) Through December 31, 2013
	(unaudited, in thousands)		
Net Income	$10,869	$18,831	$2,988
Interest expense, net of capitalized interest	317	317	—
Interest expense—related party, net of capitalized interest	—	10,755	5,741

Unit-based compensation expense	883	1,011	—
Depletion	7,971	19,602	5,199
Adjusted EBITDA	$20,040	$50,516	$13,928

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Liquidity and Capital Resources

Overview

We expect our primary sources of liquidity will be cash flows from operations and equity and debt financings, including borrowings under our revolving credit facility, 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 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 will adopt a policy to distribute an amount equal to the available cash we generate each quarter to our unitholders. Our first distribution, however, will include available cash for the period from June 23, 2014, the date of the closing 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 Parter 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 September 30, 2014, the borrowing base was set at $110.0 million. We had no outstanding borrowings as of September 30, 2014.

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 the assets of the Partnership and its subsidiaries.

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 the Partnership's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. 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.

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Cash Flows

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

	Nine Months Ended September 30, 2014	Period From Inception (September 18, 2013) Through December 31, 2013
	(in thousands)	
Cash Flow Data:		
Cash flows provided by operating activities	$29,633	$4,845
Cash flows used in investing activities	(96,814)	(4,083)
Cash flows provided by financing activities	79,923	—
Net increase in cash	$12,742	$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 nine months ended September 30, 2014 and the period from inception (September 18, 2013) to December 31, 2013, respectively.

During the nine months ended September 30, 2014, we spent approximately $57.7 million on acquisitions of mineral interests underlying approximately 10,565 gross (3,461) 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 $79.9 million during the nine months ended September 30, 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 $232.8 million, net of offering expenses and underwriting discounts and commissions. In connection with the closing of the IPO, the Partnership 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. As of September 30, 2014, the Partnership had distributed $148.8 million to Diamondback. 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 did not use any cash for financing activities during the period from inception (September 18, 2013) to December 31, 2013.

Contractual Obligations

We did not have any material contractual obligations and other commitments as of September 30, 2014.

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

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significant estimates and assumptions used in preparation of our financial statements. See the notes to our consolidated financial statements included elsewhere in this quarterly 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 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.

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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 8—Unit Based Compensation to our accompanying unaudited 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 nine months ended September 30, 2014, were completed using a Black-Scholes option valuation model, which requires us to make several assumptions.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

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 for several 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 interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the nine months ended September 30, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (71%); and Permian Transport & Trading (12%). For the period from inception (September 18, 2013) 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 revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% 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

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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 revolving credit facility on July 8, 2014, and as of September 30, 2014, we had no outstanding borrowings. On September 18, 2014, the last date on which borrowings were outstanding under our revolving credit facility, 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 revolving credit facility on September 18, 2014.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our 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 our 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 September 30, 2014, an evaluation was performed under the supervision and with the participation of management, including our 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, our Chief Executive Officer and Chief Financial Officer of our General Partner have concluded that as of September 30, 2014, 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 September 30, 2014 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.

ITEM 1A.RISK FACTORS.

Our business faces many risks. Any of the risks discussed in this Form 10-Q 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 impair our business operations.

In addition to the information set forth in this Form 10–Q, you should carefully consider the risk factors discussed in our final prospectus dated June 17, 2014 and filed with the SEC pursuant to Rule 424(b) under the Securities Act on June 18, 2014. There have been no material changes in our risk factors from those described in our prospectus filed pursuant to Rule 424(b) on June 18, 2014.

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ITEM 6.EXHIBITS.

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 Limited Partnership Agreement 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*+	Form of Phantom Unit Agreement.
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.

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* Filed herewith.

\+ Management contract, compensatory plan or arrangement.

++ 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: November 6, 2014	By: /s/ Travis D. Stice Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date: November 6, 2014	By: /s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer (Principal Financial and Accounting Officer)