Viper Energy Partners LP
Form 10-Q
October 30, 2018
Table of Contents

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

FORM 10-Q

ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2018
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 every Interactive Data File required to be submitted 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 such files). Yes ý No ¨

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

Non-Accelerated Filer o Smaller Reporting Company o

Emerging Growth Company ý

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

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 26, 2018, the registrant had outstanding 51,653,956 common units representing limited partner interests and 72,418,500 Class B units representing limited partner units.

Table of Contents

VIPER ENERGY PARTNERS LP
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2018
TABLE OF CONTENTS

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
British Thermal Unit or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf	Thousand cubic feet of natural gas.
MMBtu	Million British Thermal Units.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Reserves	The estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves are not assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other

	reservoirs.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Table of Contents

GLOSSARY OF CERTAIN OTHER TERMS

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

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

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements may include statements about:

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

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

Table of Contents

Viper Energy Partners LP
Consolidated Balance Sheets
(Unaudited)

	September 30, 2018	December 31, 2017
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$16,829	$24,197
Royalty income receivable	38,018	25,754
Royalty income receivable—related party	7,758	5,142
Other current assets	146	355
Total current assets	62,751	55,448
Property:		
Oil and natural gas interests, full cost method of accounting ($832,414 and $514,724 excluded from depletion at September 30, 2018 and December 31, 2017, respectively)	1,612,425	1,103,897
Land	5,688	—
Accumulated depletion and impairment	(230,784)	(189,466)
Property, net	1,387,329	914,431
Funds held in escrow	—	6,304
Other assets	23,346	36,854
Deferred tax asset	95,551	—
Total assets	$1,568,977	$1,013,037
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable	$4	$2,960
Other accrued liabilities	4,706	2,669
Total current liabilities	4,710	5,629
Long-term debt	296,500	93,500
Total liabilities	301,210	99,129
Commitments and contingencies (Note 12)		
Unitholders' equity:		
General partner	1,000	—
Common units (51,653,956 units issued and outstanding as of September 30, 2018 and 113,882,045 units issued and outstanding as of December 31, 2017)	570,227	913,908
Class B units (72,418,500 units issued and outstanding as of September 30, 2018 and 0 units issued and outstanding as of December 31, 2017)	990	—
Total unitholders' equity	572,217	913,908
Non-controlling interest	695,550	—
Total liabilities and unitholders' equity	$1,568,977	$1,013,037

See accompanying notes to consolidated financial statements.

Table of Contents

Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$74,386	$42,211	$211,199	$110,194
Lease bonus income	4,205	322	5,133	2,613
Other operating income	12	—	120	—
Total operating income	78,603	42,533	216,452	112,807
Costs and expenses:				
Production and ad valorem taxes	5,027	2,825	14,133	7,668
Gathering and transportation	889	205	1,297	492
Depletion	16,532	11,068	41,317	28,587
General and administrative expenses	1,309	1,368	6,230	5,064
Total costs and expenses	23,757	15,466	62,977	41,811
Income from operations	54,846	27,067	153,475	70,996
Other income (expense):				
Interest expense, net	(3,711)	(859)	(9,061)	(2,114)
Gain (loss) on revaluation of investment	(199)	—	5,165	—
Other income, net	640	399	1,479	526
Total other income (expense), net	(3,270)	(460)	(2,417)	(1,588)
Income before income taxes	51,576	26,607	151,058	69,408
Provision for (benefit from) income taxes	764	—	(71,114)	—
Net income	50,812	26,607	222,172	69,408
Net income attributable to non-controlling interest	48,466	—	77,526	—
Net income attributable to Viper Energy Partners LP	$2,346	$26,607	$144,646	$69,408
Net income attributable to common limited partners per unit:				
Basic	$0.05	$0.24	$1.85	$0.69
Diluted	$0.05	$0.24	$1.85	$0.69
Weighted average number of common limited partner units outstanding:				
Basic	48,234	110,377	78,250	101,095
Diluted	48,304	110,424	78,319	101,143

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Limited Partners				General Partner	Non-Controlling Interest	
	Common Units	Amount	Class B Units	Amount	Amount	Amount	Total
		(In thousands)					
Balance at December 31, 2016	87,800	$547,898	—	$ —	$ —	$ —	$547,898
Net proceeds from the issuance of common units - public	25,175	369,896		—	—	—	369,896
Net proceeds from the issuance of common units - Diamondback	700	10,067		—	—	—	10,067
Common units issued for acquisition	175	3,050		—	—	—	3,050
Unit-based compensation	32	2,039		—	—	—	2,039
Distributions to public		(27,640)		—	—	—	(27,640)
Distributions to Diamondback		(64,858)		—	—	—	(64,858)
Net income		69,408		—	—	—	69,408
Balance at September 30, 2017	113,882	$909,860	—	$ —	$ —	$ —	$909,860
Balance at December 31, 2017	113,882	$913,908	—	$ —	$ —	$ —	$913,908
Impact of adoption of ASU 2016-01 (Note 2)		(18,651)		—	—	—	(18,651)
Unit exchange related to tax conversion	(73,150)	(545,441)	73,150	1,000	1,000	545,441	2,000
Recapitalization related to tax conversion	732	—	(732)	(10)	—	—	(10)
Net proceeds from the issuance of common units - public	10,080	303,137		—	—	—	303,137
Unit-based compensation	102	2,166		—	—	—	2,166
Unit options exercised	8	140		—	—	—	140
Distributions to public		(68,789)		—	—	—	(68,789)
Distributions to Diamondback		(69,211)		—	—	(43,451)	(112,662)
Distributions to General Partner		(11)		—	—	—	(11)
Change in ownership of consolidated subsidiaries, net		(91,667)		—	—	116,034	24,367
Net income		144,646		—	—	77,526	222,172
Balance at September 30, 2018	51,654	$570,227	72,419	$ 990	$ 1,000	$ 695,550	$1,267,767

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$222,172	$69,408
Adjustments to reconcile net income to net cash provided by operating activities:		
Benefit from deferred income taxes	(71,184)	—
Depletion	41,317	28,587
Gain on revaluation of investment	(5,165)	—
Amortization of debt issuance costs	521	434
Non-cash unit-based compensation	2,166	2,039
Changes in operating assets and liabilities:		
Restricted cash	—	500
Royalty income receivable	(12,264)	(7,156)
Royalty income receivable—related party	(2,616)	(176)
Accounts payable and other accrued liabilities	1,315	367
Income tax payable	69	—
Other current assets	83	54
Net cash provided by operating activities	176,414	94,057
Cash flows from investing activities:		
Acquisition of oil and natural gas interests	(505,842)	(301,133)
Other	(4,687)	—
Proceeds from sale of assets	441	—
Proceeds from the sale of investments	124	—
Net cash used in investing activities	(509,964)	(301,133)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	557,000	220,500
Repayment on credit facility	(354,000)	(305,500)
Debt issuance costs	(623)	(180)
Proceeds from public offerings	305,773	380,412
Public offering costs	(2,636)	(433)
Proceeds from exercise of unit options	140	—
Contributions by members	2,000	—
Distributions to partners	(181,472)	(92,498)
Net cash provided by financing activities	326,182	202,301
Net decrease in cash	(7,368)	(4,775)
Cash and cash equivalents at beginning of period	24,197	9,213
Cash and cash equivalents at end of period	$16,829	$4,438
Supplemental disclosure of cash flow information:		
Interest paid	$8,147	$1,781

See accompanying notes to consolidated financial statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

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

Recapitalization, Tax Status Election and Related Transactions

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

On May 10, 2018, the change in the Partnership’s income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) Diamondback made a cash capital contribution of $1.0 million to the Partnership in respect of the Class B units. Diamondback, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, Diamondback also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as the Partnership’s general partner and Diamondback continues to control the Partnership. After the effectiveness of the tax status election and the completion of related transactions, the Partnership’s minerals business continues to be conducted through the

Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to the Partnership’s business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to the Partnership’s Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and the Partnership’s Current Report on Form 8-K filed with the SEC on May 15, 2018.

Basis of Presentation

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

These financial statements have been prepared by the Partnership without audit, pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature.

Table of Contents

Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been omitted pursuant to such rules and regulations, although the Partnership believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Partnership’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2017, which contains a summary of the Partnership’s significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

The Partnership evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Partnership considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Partnership’s estimates. Any effects on the Partnership’s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas interests and unit–based compensation.

Investments

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over the limited partnership’s operating and financial policies. This interest was acquired during the year ended December 31, 2014 and is accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption. For the three and nine months ended September 30, 2018, the Partnership recorded a loss of $0.2 million and a gain of $5.2 million, respectively, which then increased the Partnership’s investment balance to $20.2 million, which is included in other assets in the accompanying consolidated balance sheets.

Income Taxes

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

The Partnership is subject to margin tax in the state of Texas pursuant to a tax sharing agreement with Diamondback, as discussed further in Note 7. The Partnership's 2015 through 2017 tax years, periods during which the Partnership was organized as a pass-through entity for income tax purposes, remain open to examination by tax authorities. As of September 30, 2018 and September 30, 2017, the Partnership had no unrecognized tax benefits that would have a material impact on the effective tax rate. The Partnership is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the nine months ended September 30, 2018, 2017 and 2016, there was no interest or penalties associated with uncertain tax positions recognized in the Partnership's consolidated financial statements.

New Accounting Pronouncements

Recently Adopted Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements. This standard included a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for those goods or services. Among other things, the standard also eliminated industry-specific revenue guidance, required enhanced disclosures about revenue, provided guidance for transactions that were not previously addressed comprehensively and improved guidance for multiple-element arrangements. The Partnership adopted this standard effective January 1, 2018 using the modified retrospective method. The Partnership utilized a bottom-up approach to analyze the impact of the new standard by reviewing its current accounting policies and practices to identify potential differences that would result from applying the requirements of the new standard to its revenue contracts and the impact of adopting this standard on its total revenues, operating income and the Partnership's consolidated balance sheet. The adoption of this standard did not result in a cumulative-effect adjustment.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, "Financial Instruments–Overall". This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. The Partnership adopted this standard effective January 1, 2018 by means of a negative cumulative-effect adjustment totaling $18.7 million.

In November 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-18, "Statement of Cash Flows - Restricted Cash". This update affects entities that have restricted cash or restricted cash equivalents. The Partnership adopted this update effective January 1, 2018. The adoption of this update did not have an effect on the presentation on the Statement of Cash Flows.

In January 2017, the Financial Accounting Standards Board issued Accounting Standards Update 2017-01, "Business Combinations - Clarifying the Definition of a Business". This update apples to all entities that must determine whether they acquired or sold a business. This update provides a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. The Partnership adopted this update prospectively effective January 1, 2018. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, "Leases". This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. As of September 30, 2018, the Partnership was not the lessor or lessee of any leases other than mineral leases which were excluded from the scope of this Accounting Standards Update. Therefore, the Partnership believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In January 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-01, "Leases - Land Easement Practical Expedient for Transition to Topic 842". This update applies to any entity that holds land easements. The update allows entities to adopt a practical expedient to not evaluate existing or expired land easements under Topic 842 that were not previously accounted for as leases under the current leases guidance. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. The Partnership believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-10, "Codification Improvements to Topic 842, Leases". This update provides clarification and corrects unintended application of certain sections in the new lease guidance. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity. The Partnership is still evaluating the impact of this standard.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-11, "Lease (Topic 842): Targeted Improvements". This update provides another transition method of allowing entities to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity. The Partnership is still evaluating the impact of this standard.

In June 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-13, “Financial Instruments - Credit Losses”. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Partnership does not believe the adoption of this standard will have an impact on its financial statements since it does not have a history of credit losses.

In June 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-07, “Stock Compensation - Improvements to Nonemployee Share-Based Payment Accounting”. This update applies the existing employee guidance to nonemployee share-based transactions, with the exception of specific guidance related to the attribution of compensation cost. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact on its financial position, results of operations or liquidity. The Partnership is still evaluating the impact of this standard.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-09, “Codification Improvements”. This update provides clarification and corrects unintended application of the guidance in various sections. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact on its financial position, results of operations or liquidity. The Partnership is still evaluating the impact of this standard.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

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

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

Transaction price allocated to remaining performance obligations

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

Contract balances

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

Prior-period performance obligations

The Partnership records revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and natural gas liquids sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Partnership is required to estimate the amount of royalty income to be received based upon the Partnership's interest. The Partnership records the differences between its estimates and the actual amounts received for royalties in the month that payment is received from the producer. The Partnership has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the three and nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Partnership believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded.

4. ACQUISITIONS

2018 Activity

During the nine months ended September 30, 2018, the Partnership acquired from unrelated third parties mineral interests underlying 2,651 net royalty acres for an aggregate purchase price of approximately $521.2 million and, as of September 30, 2018, had mineral interests underlying 13,908 net royalty acres. The Partnership funded these acquisitions with cash on hand and borrowings under its revolving credit facility.

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

2017 Activity

During the nine months ended September 30, 2017, the Partnership acquired mineral interests underlying 2,769 net royalty acres for an aggregate purchase price of approximately $304.6 million and, as of September 30, 2017, had mineral interests underlying 9,173 net royalty acres. The Partnership funded these acquisitions with cash on hand, borrowings under its revolving credit facility, a portion of the net proceeds from its January and July 2017 offerings of common units and the issuance of 174,513 common units to the seller in a private placement in May 2017.

Table of Contents

5. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	September 30, 2018	December 31, 2017
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$780,011	$589,173
Not subject to depletion	832,414	514,724
Gross oil and natural gas interests	1,612,425	1,103,897
Accumulated depletion and impairment	(230,784)	(189,466)
Oil and natural gas interests, net	1,381,641	914,431
Land	5,688	—
Property, net of accumulated depletion and impairment	$1,387,329	$914,431
Balance of acquisition costs not subject to depletion:		
Incurred in 2018	$389,628	
Incurred in 2017	284,371	
Incurred in 2016	158,157	
Incurred in 2015	258	
Total not subject to depletion	$832,414	

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

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

6. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement as amended and restated, (the “credit facility”) with Wells Fargo, as administrative agent, certain other lenders, and the Partnership’s consolidated subsidiary, Viper Energy Partners LLC (the “Operating Company”), as guarantor. On May 8, 2018, the Operating Company assumed all liabilities as borrower under the credit agreement and the Partnership became a guarantor of the credit agreement. On July 20, 2018, the Operating Company, the Partnership, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company. The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on its oil and natural gas reserves and other factors (the “borrowing base”) of $475.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and October 26th. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of September 30, 2018, the borrowing base was set at $475.0 million, and there was $296.5 million of outstanding borrowings and $178.5 million available for future borrowings under the credit facility. In connection with the Partnership’s fall 2018 redetermination, the Partnership’s borrowing base was increased to $555.0 million effective October 26, 2018.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Operating Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. The Operating Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of the assets of the Partnership and the Operating Company.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements, and require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Ratio of total net debt to EBITDAX, as defined in the credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 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.

As of September 30, 2018, the Operating Company was in compliance with the financial covenants under its credit agreement. The lenders may accelerate all of the indebtedness under the revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of the credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

7. RELATED PARTY TRANSACTIONS

Partnership Agreement

The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018 (the “Partnership Agreement”), requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership’s behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership’s business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on the Partnership’s behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership. For the three and nine months ended September 30, 2018 and 2017, the General Partner allocated \$0.6 million and \$1.8 million, respectively, to the Partnership.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement with Wexford Capital LP (“Wexford”) dated as of June 23, 2014 (the “Advisory Services Agreement”), under which Wexford provides the Partnership and the General Partner with general financial and strategic advisory services related to the Partnership’s business in return for an annual fee of \$0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on June 23, 2014, and continues for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. For the three and nine months ended September 30, 2018 and 2017, the Partnership did not pay any amounts under the Advisory Services Agreement.

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership's results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership's benefit, even though Diamondback had no cash tax expense for that period. For the three and nine months ended September 30, 2018, the Partnership accrued state income tax expense (benefit) of $(0.1) million and $0.1 million, respectively, for its share of Texas margin tax for which the Partnership's results are included in a combined tax return filed by Diamondback.

Lease Bonus

During the three and nine months ended September 30, 2018, Diamondback paid the Partnership $2.9 million in lease bonus payments to extend the term of 12 leases, reflecting an average bonus of $6,412 per acre. During the three months ended September 30, 2017, Diamondback did not pay the Partnership any lease bonus payments. During the nine months ended September 30, 2017, Diamondback paid the Partnership $0.1 million in lease bonus payments to extend the term of two leases, reflecting an average bonus of $7,459 per acre.

8. UNIT-BASED COMPENSATION

In connection with the IPO, the board of directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan ("LTIP"), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. The LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. As of September 30, 2018, a total of 9,007,760 common units had been reserved for issuance pursuant to the LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The LTIP is administered by the board of directors of the General Partner or a committee thereof.

For the three and nine months ended September 30, 2018, the Partnership incurred $0.4 million and $2.2 million, respectively, of unit–based compensation.

Unit Options

The following table presents the unit option activity under the LTIP for the nine months ended September 30, 2018:

	Unit Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Intrinsic Value
			(in years)	(in thousands)
Outstanding at December 31, 2017	7,600	$18.49		
Exercised	(7,600)	$18.49		
Outstanding at September 30, 2018	—	$—	0.00	$ —

The aggregate intrinsic value of unit options that were exercised during the nine months ended September 30, 2018 were $0.2 million.

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

Phantom Units

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

The following table presents the phantom unit activity under the LTIP for the nine months ended September 30, 2018:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	105,439	$ 17.10
Granted	119,818	$ 24.46
Vested	(102,811)	$ 19.23
Unvested at September 30, 2018	122,446	$ 22.52

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2018 was $2.0 million. As of September 30, 2018, the unrecognized compensation cost related to unvested phantom units was $2.0 million. Such cost is expected to be recognized over a weighted-average period of 1.3 years.

9. UNITHOLDERS' EQUITY AND PARTNERSHIP DISTRIBUTIONS

The Partnership has general partner and limited partner units. At September 30, 2018, the Partnership had a total of 51,653,956 common units issued and outstanding and 72,418,500 Class B units outstanding, of which 731,500 common units and 72,418,500 Class B units were owned by Diamondback, representing approximately 59% of the total Partnership's units outstanding. The Operating Company units and the Partnership's Class B units owned by Diamondback are exchangeable from time to time for the Partnership's common units (that is, one Operating Company unit and one Partnership Class B unit, together, will be exchangeable for one Partnership common unit).

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

	Common Units
Balance at December 31, 2017	113,882,045
Common units issued in public offerings	10,080,000
Common units vested and issued under the LTIP	110,411
Unit exchange related to tax conversion	(73,150,000)
Recapitalization related to tax conversion	731,500
Balance at September 30, 2018	51,653,956

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

	Class B Units
Balance at December 31, 2017	—

Unit exchange related to tax conversion	73,150,000
Recapitalization related to tax conversion	(731,500)
Balance at September 30, 2018	72,418,500

In January 2017, the Partnership completed an underwritten public offering of 9,775,000 common units, which included 1,275,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. The Partnership received net proceeds from this offering of approximately $147.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which $120.5 million was used to repay the outstanding borrowings under the revolving credit agreement and the balance was used for general partnership purposes, which included additional acquisitions.

In July 2017, the Partnership completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Diamondback purchased 700,000 common units, an affiliate of the General Partner purchased 3,000,000 common units and certain officers and directors of Diamondback and the General Partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. The Partnership received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which the Partnership used $152.8 million to repay all of the then-outstanding borrowings under the revolving credit facility and the balance was used to fund a portion of the purchase price for acquisitions and for general partnership purposes, which included additional acquisitions.
In July 2018, the Partnership completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 59% of the total Partnership units then outstanding. The Partnership received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under the revolving credit facility.

The board of directors of the General Partner has adopted a policy for the Partnership to distribute all available cash generated on a quarterly basis, beginning with the quarter ended September 30, 2014.

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

	Amount per Common Unit	Declaration Date	Unitholder Record Date	Payment Date
Q4 2017	$ 0.46	January 31, 2018	February 19, 2018	February 26, 2018
Q1 2018	$ 0.48	April 5, 2018	April 20, 2018	April 27, 2018
Q2 2018	$ 0.60	July 27, 2018	August 13, 2018	August 20, 2018

Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of the General Partner following the end of such quarter. Available cash for each quarter will generally equal Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of the General Partner deems necessary or appropriate, if any.

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 for the three and nine months ended September 30, 2018 and 2017, 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. Payments made to the Partnership’s unitholders are determined in relation to the cash distribution policy described in Note 9—Unitholders’ Equity and Partnership Distributions.

Basic net income per common unit is calculated by dividing net income by the weighted-average number of common units outstanding during the period. Diluted net income per common unit gives effect, when applicable, to unvested common units granted under the LTIP.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands, except per unit amounts)			
Net income attributable to the period	$2,346	$26,607	$144,646	$69,408
Weighted average common units outstanding:				
Basic weighted average common units outstanding	48,234	110,377	78,250	101,095
Effect of dilutive securities:				
Potential common units issuable	70	47	69	48
Diluted weighted average common units outstanding	48,304	110,424	78,319	101,143
Net income per common unit, basic	$0.05	$0.24	$1.85	$0.69
Net income per common unit, diluted	$0.05	$0.24	$1.85	$0.69

For the three months ended September 30, 2018 and 2017, there were no common units and 1,356 common units, respectively, and for nine months ended September 30, 2018 and 2017, there were 1,092 common units and 43,414 common units, respectively, that were not included in the computation of diluted earnings per common unit because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per common unit in future periods.

11. INCOME TAXES

As discussed further in Note 1, on March 29, 2018, the Partnership announced that the Board of Directors of the General Partner had unanimously approved a change of the Partnership’s federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. Subsequent to the Partnership’s change in tax status, the Partnership’s provision for income taxes for the period ended September 30, 2018 is based on the estimated annual effective tax rate plus discrete items.

The Partnership’s effective income tax rate was (47.1)% for the nine months ended September 30, 2018. Total income tax benefit for the nine months ended September 30, 2018 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to (i) the impact of deferred taxes recognized as a result of the Partnership’s change in tax status, (ii) net income attributable to the non-controlling interest, and (iii) net income attributable to the period prior to the Partnership’s change in federal income tax status. For the nine months ended September 30, 2018, the Partnership recorded a discrete income tax benefit of approximately $72.7 million related to deferred taxes on the Partnership’s investment in the Operating Company arising from the change in the Partnership’s federal tax status.

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

12. COMMITMENTS AND CONTINGENCIES

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

13. SUBSEQUENT EVENTS

Cash Distribution

On October 23, 2018, the board of directors of the General Partner approved a cash distribution for the third quarter of 2018 of $0.58 per common unit, payable on November 19, 2018, to unitholders of record at the close of business on November 12, 2018.

Table of Contents

The Partnership’s Credit Facility

In connection with the Partnership’s fall 2018 redetermination, the Partnership’s borrowing base was increased to $555.0 million effective October 26, 2018.

Table of Contents

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

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2017. 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 and the Eagle Ford Shale. As of September 30, 2018, our general partner had a 100% general partner interest in us, and Diamondback owned 731,500 common units and all of our 72,418,500 outstanding Class B units, representing approximately 59% of our total units outstanding. Diamondback also owns and controls our general partner.

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

Sources of Our Income

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Royalty income				
Oil sales	81 %	85 %	86 %	86 %
Natural gas sales	5 %	7 %	4 %	6 %
Natural gas liquid sales	9 %	7 %	8 %	6 %
Lease bonus income	5 %	1 %	2 %	2 %
	100 %	100 %	100 %	100 %

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

During 2017, West Texas Intermediate posted prices ranged from $42.48 to $60.46 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. During the first nine months of 2018, West Texas Intermediate posted prices ranged from $59.20 to $77.41 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On September 28, 2018, the West Texas Intermediate posted price for crude oil was $73.16 per Bbl and the Henry Hub spot market price of natural gas was $3.01 per MMBtu. Lower prices may not only decrease our income, but also potentially the amount of oil and natural gas that our operators can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under the credit agreement, which may be redetermined at the discretion of our lenders.

Recent Acquisitions

During the nine months ended September 30, 2018, we acquired from unrelated third parties 2,651 net royalty acres for an aggregate purchase price of $521.2 million, subject to post-closing adjustments, bringing our total mineral interests to 13,908 net royalty acres as of September 30, 2018.

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

Production and Operational Update

Our average daily production during the third quarter of 2018 was 18,384 BOE/d (69% oil), and our operators received an average of $54.51 per Bbl of oil, $27.05 per Bbl of natural gas liquids and $2.42 per Mcf of natural gas, for an average realized price of $43.98 per BOE.

During the third quarter of 2018, the operators of our Spanish Trail mineral interests brought online eight gross horizontal wells with an average royalty interest of 21.9%, consisting of six Middle Spraberry, two Lower Spraberry, two Wolfcamp A and two Wolfcamp B wells. As of September 30, 2018, there were 17 horizontal wells with an average royalty interest of 19.8% in various stages of drilling or completion on this acreage. Additionally, there is active development activity on our mineral acreage outside of Spanish Trail in Loving, Reeves, Midland, Pecos, Ward, Martin, Howard and Glasscock counties. As of September 30, 2018, we had 1,101 vertical wells and 2,183 horizontal wells producing on our acreage. As of October 22, 2018, there were 24 active rigs on our acreage and 523 active drilling permits filed in the past six months.

We declared a cash dividend for the third quarter of 2018 of $0.58 per common unit, payable on November 19, 2018, to unitholders of record at the close of business on November 12, 2018.

Recapitalization, Tax Status Election and Related Transactions

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

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

Principal Components of Our Cost Structure

Production and Ad Valorem Taxes

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

General and Administrative

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

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

Depletion

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

Income Tax Expense

Prior to our change in federal income tax status, we were organized as a pass-through entity for income tax purposes. As a result, our partners were responsible for federal income taxes on their share of our taxable income.

We are subject to the Texas margin tax. For the nine months ended September 30, 2018 and 2017, the Partnership accrued $0.1 million and $0, respectively, for Texas margin tax payable pursuant to our tax sharing agreement with Diamondback.

Table of Contents

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Operating Results:				
Operating income:				
Royalty income	$74,386	$42,211	$211,199	$110,194
Lease bonus income	4,205	322	5,133	2,613
Other operating income	12	—	120	—
Total operating income	78,603	42,533	216,452	112,807
Costs and expenses:				
Production and ad valorem taxes	5,027	2,825	14,133	7,668
Gathering and transportation	889	205	1,297	492
Depletion	16,532	11,068	41,317	28,587
General and administrative expenses	1,309	1,368	6,230	5,064
Total costs and expenses	23,757	15,466	62,977	41,811
Income from operations	54,846	27,067	153,475	70,996
Other income (expense):				
Interest expense, net	(3,711)	(859)	(9,061)	(2,114)
Gain (loss) on revaluation of investment	(199)	—	5,165	—
Other income, net	640	399	1,479	526
Total other income (expense), net	(3,270)	(460)	(2,417)	(1,588)
Income before income taxes	51,576	26,607	151,058	69,408
Provision for (benefit from) income taxes	764	—	(71,114)	—
Net income	50,812	26,607	222,172	69,408
Net income attributable to non-controlling interest	48,466	—	77,526	—
Net income attributable to Viper Energy Partners LP	$2,346	$26,607	$144,646	$69,408

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Production Data:				
Oil (MBbls)	1,167	794	3,125	2,078
Natural gas (MMcf)	1,624	1,236	4,067	2,461
Natural gas liquids (MBbls)	254	160	645	394
Combined volumes (MBOE)	1,691	1,160	4,448	2,882
Daily combined volumes (BOE/d)	18,384	12,611	16,232	10,555
% Oil	69 %	68 %	70 %	72 %
Average sales prices:				
Oil (per Bbl)	$54.51	$45.33	$59.26	$46.51
Natural gas (per Mcf)	2.42	2.55	2.25	2.62
Natural gas liquids (per Bbl)	27.05	19.10	26.16	18.07
Combined (per BOE)	43.98	36.38	47.49	38.24
Average Costs ($/BOE):				
Production and ad valorem taxes	$2.97	$2.43	$3.18	$2.66
Gathering and transportation expense	0.53	0.18	0.29	0.17
General and administrative - cash component	0.52	0.75	0.91	1.05
Total operating expense - cash	$4.02	$3.36	$4.38	$3.88
General and administrative - non-cash component	$0.25	$0.43	$0.49	$0.71
Interest expense, net	2.19	0.74	2.04	0.73
Depletion	9.77	9.54	9.29	9.92

Comparison of the Three Months Ended September 30, 2018 and 2017

Royalty Income

Our royalty income for the three months ended September 30, 2018 and 2017 was $74.4 million and $42.2 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

Table of Contents

In addition to the increase in average prices received during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017, we also benefited from a 45.8% increase in combined volumes sold by our operators as compared to the three months ended September 30, 2017.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 9.18	1,167	$ 10,703
Natural gas	(0.13)	1,624	(211)
Natural gas liquids	7.95	254	2,019
Total income due to change in price			$ 12,511

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	372	$ 45.33	$ 16,877
Natural gas	388	2.55	989
Natural gas liquids	94	19.10	1,798
Total income due to change in production volumes			19,664
Total change in income			$ 32,175

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

Lease Bonus Income

Lease bonus income increased by $3.9 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. During the three months ended September 30, 2018, we received $4.2 million in lease bonus payments to extend the term of 13 leases, reflecting an average bonus of $7,369 per acre. During the three months ended September 30, 2017, we received $0.3 million in lease bonus payments to extend the term of one lease, reflecting an average bonus of $10,000 per acre.

Net Interest Expense

The net interest expense for the three months ended September 30, 2018 and 2017 reflects the interest incurred under our credit agreement. Net interest expense for the three months ended September 30, 2018 and 2017 was $3.7 million and $0.9 million, respectively. The increase of approximately $2.9 million was due to a higher interest rate and increased borrowings during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017.

Provision for (Benefit From) Income Taxes

We recorded an income tax expense of $0.8 million for the three months ended September 30, 2018. Prior to the second quarter of 2018, we had no provision for or benefit from income taxes. Total income tax benefit for the three months ended September 30, 2018 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the period primarily due to net income attributable to non-controlling interest and net income attributable to the period prior to our change in federal income tax status.

Comparison of the Nine Months Ended September 30, 2018 and 2017

Royalty Income

Our royalty income for the nine months ended September 30, 2018 and 2017 was $211.2 million and $110.2 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

Table of Contents

In addition to the increase in average prices received during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, we also benefited from a 54.3% increase in combined volumes sold by our operators as compared to the nine months ended September 30, 2017.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 12.75	3,125	$ 39,840
Natural gas	(0.37)	4,067	(1,505)
Natural gas liquids	8.09	645	5,220
Total income due to change in price			$ 43,555

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	1,047	$ 46.51	$ 48,701
Natural gas	1,606	2.62	4,208
Natural gas liquids	251	18.07	4,541
Total income due to change in production volumes			57,450
Total change in income			$ 101,005

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

Lease Bonus Income

Lease bonus income increased by $2.5 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. During the nine months ended September 30, 2018, we received $5.1 million in lease bonus payments to extend the term of 16 leases, reflecting an average bonus of $7,090 per acre. During the nine months ended September 30, 2017, we received $2.6 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $3,333 per acre.

Other Operating Income

Other operating income was $0.1 million for the nine months ended September 30, 2018 primarily related to surface damage payments. We did not receive any other operating income for the nine months ended September 30, 2017.

General and Administrative Expenses

The general and administrative expenses primarily reflect costs associated with us being a publicly traded limited partnership, unit-based compensation and the amounts reimbursed to our general partner under our partnership agreement. For the nine months ended September 30, 2018 and 2017, we incurred general and administrative expenses of $6.2 million and $5.1 million, respectively. The increase of $1.2 million during the nine months ended September 30, 2018 was primarily due to expenses related to the change in tax status.

Net Interest Expense

The net interest expense for the nine months ended September 30, 2018 and 2017 reflects the interest incurred under our credit agreement. Net interest expense for the nine months ended September 30, 2018 and 2017 was $9.1 million and $2.1 million, respectively. The increase of $6.9 million was due to a higher interest rate and increased borrowings during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017.

Table of Contents

Provision for (Benefit From) Income Taxes

We recorded an income tax benefit of $71.1 million for the nine months ended September 30, 2018 due to the change in our federal income tax status. Prior to the second quarter of 2018, we had no provision for or benefit from income taxes. Total income tax benefit for the nine months ended September 30, 2018 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the period primarily due to deferred taxes recognized as a result of our change in federal income tax status.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations 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 common unitholders.

We define Adjusted EBITDA as net income plus interest expense, net, non-cash unit-based compensation expense, depletion expense, gain on revaluation of investment and provision for (benefit from) income taxes. Adjusted EBITDA is not a measure of net income as determined by GAAP. We exclude the items listed above from net income 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, or more meaningful than, 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,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Net income	$50,812	$26,607	$222,172	$69,408
Interest expense, net	3,711	859	9,061	2,114
Non-cash unit-based compensation expense	426	503	2,166	2,039
Depletion	16,532	11,068	41,317	28,587
Loss (gain) on revaluation of investment	199	—	(5,165)	—
Provision for (benefit from) income taxes	764	—	(71,114)	—
Consolidated Adjusted EBITDA	72,444	39,037	198,437	102,148
EBITDA attributable to non-controlling interest	(42,256)	—	(85,898)	—
Adjusted EBITDA attributable to Viper Energy Partners LP	$30,188	$39,037	$112,539	$102,148

24

Table of Contents

Liquidity and Capital Resources

Overview

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

Our partnership agreement does not require us to distribute any of the cash we generate from operations. However, the board of directors of our general partner has adopted a policy pursuant to which the Operating Company will distribute all of the available cash it generates each quarter to its unitholders (including us), and we, in turn, will distribute all of the available cash we receive from the Operating Company to our common unitholders.

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

On October 23, 2018, the board of directors of the General Partner approved a cash distribution for the third quarter of 2018 of $0.58 per common unit, payable on November 19, 2018, to unitholders of record at the close of business on November 12, 2018.

July 2018 Equity Offering

In July 2018, we completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximately 59% of our total units then outstanding. We received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and estimated offering expenses. We used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under the revolving credit facility.

Our Credit Agreement

On July 8, 2014, we entered into a secured revolving credit agreement, or revolving credit facility, with Wells Fargo, as administrative agent, certain other lenders, and the Operating Company as guarantor. On May 8, 2018, the Operating Company assumed all liabilities as borrower under the credit agreement and we became a guarantor of the credit agreement. On July 20, 2018, we, the Operating Company, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company. The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on our oil and natural gas reserves and other factors (the “borrowing base”) of $475.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and October 26th. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of September 30, 2018, the borrowing base was set at $475.0 million, and we had $296.5 million of outstanding borrowings and $178.5 million available for future borrowings under our revolving credit facility. In connection with our fall 2018 redetermination, our borrowing base was increased to $555.0 million effective October 26, 2018.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit

Table of Contents

amount and the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of our and our subsidiary's assets.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements, and require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Ratio of total net debt to EBITDAX, as defined in the credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 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.

As of September 30, 2018, the Operating Company was in compliance with the financial covenants under its credit agreement. The lenders may accelerate all of the indebtedness under the Operating Company's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of our credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Cash Flows

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

	Nine Months Ended September 30,	
	2018	2017
	(in thousands)	
Cash Flow Data:		
Net cash flows provided by operating activities	$176,414	$94,057

Net cash flows used in investing activities	(509,964)	(301,133)
Net cash flows provided by financing activities	326,182	202,301
Net decrease in cash	$(7,368)	$(4,775)

Operating Activities

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

Investing Activities

Net cash used in investing activities was $510.0 million and $301.1 million during the nine months ended September 30, 2018 and 2017, respectively, and related to acquisitions of oil and natural gas interests and land.

Financing Activities

Net cash provided by financing activities was $326.2 million during the nine months ended September 30, 2018, primarily related to proceeds from net borrowings under our credit facility of $203.0 million and net proceeds from our public offering of common units of $303.1 million, partially offset by distributions of $181.5 million to our unitholders during the period. Net cash provided by financing activities was $202.3 million during the nine months ended September 30, 2017, primarily related to net proceeds of $380.0 million from our public offerings of common units, substantially offset by the net repayment of $85.0 million of borrowings under our revolving credit agreement and distributions of $92.5 million to our unitholders during that period.

Contractual Obligations

Except as described in our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018 and our Current Report on Form 8-K filed with the SEC on June 15, 2018, there were no material changes in our contractual obligations and other commitments as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

Critical Accounting Policies

There have been no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

Credit Risk

We are subject to risk resulting from the concentration of royalty income in producing oil and natural gas interests and receivables with several significant purchasers. For the nine months ended September 30, 2018, two purchasers each accounted for more than 10% of our royalty income: Shell Trading (US) Company (41%) and RSP Permian LLC

(16%). For the nine months ended September 30, 2017, two purchasers each accounted for more than 10% of our royalty income: Shell Trading (US) Company (48%) and RSP Permian LLC (23%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our credit agreement. The terms of our credit agreement provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% in the case of the alternative base rate and from 1.75% to 2.75% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We entered into this credit agreement on July 8, 2014, as subsequently amended, and as of September 30, 2018, we had $296.5 million in outstanding borrowings. Our weighted average interest rate on borrowings under our revolving credit facility was 4.40%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $3.0 million based on the $296.5 million outstanding in the aggregate under our credit agreement.

ITEM 4. CONTROLS AND PROCEDURES

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

As of September 30, 2018, an evaluation was performed under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon the evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner have concluded that as of September 30, 2018, 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, 2018 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 report and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, you should carefully consider the risk factors included in our most recent Annual Report on Form 10-K (except as described therein under "Risk Related to Recently Enacted U.S.

Tax Legislation and Tax Risks to Common Unitholders"), Quarterly Reports on Form 10-Q and Current Reports on Form 8-K that we file with the SEC, which are incorporated by reference herein. We also incorporate by reference herein our updated risk factors under "Risks Inherent in an Investment in Us" included in our Registration Statement on Form S-3ASR (File No. 333-226411) filed with the SEC on July 30, 2018. Due to the change in our federal income tax status, the risks described under "Risks Related to Recently Enacted U.S. Tax Legislation and Tax Risks to Common Unitholders" in our Annual Report on Form 10-K are no longer applicable to us or an investment in our common units.

Table of Contents

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Viper Energy Partners LP (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement on Form S-1 (File No. 333-195769) filed on May 7, 2014).
3.2	Second Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP, dated as of May 9, 2018 (incorporated by reference to 3.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
3.3	First Amendment to Second Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP, dated as of May 10, 2018. (incorporated by reference to Exhibit 3.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
3.4	Second Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, dated as of May 9, 2018. (incorporated by reference to Exhibit 3.3 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
4.1	Amended and Restated Registration Rights Agreement, dated as of May 9, 2018, by and between Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2018).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

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

Table of Contents

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:	October 30, 2018	By:	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer
Date:	October 30, 2018	By:	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer