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

FORM 10-Q

☒ **QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE QUARTERLY PERIOD ENDED September 30, 2019
OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-36505

Viper Energy Partners LP
(Exact Name of Registrant As Specified in Its Charter)

DE	**46-5001985**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas	
Suite 1200	
Midland, TX	**79701**
(Address of principal executive offices)	**(Zip code)**

(432) 221-7400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	VNOM	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

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

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

As of October 25, 2019, the registrant had outstanding 62,653,583 common units representing limited partner interests and 90,709,946 Class B units representing limited partner units.

VIPER ENERGY PARTNERS LP

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2019

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Basin	A large depression on the earth’s surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
British Thermal Unit or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Condensate	Liquid hydrocarbons associated with the production of a primarily natural gas reserve.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Fracturing	The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf	Thousand cubic feet of natural gas.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
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.
WTI	West Texas Intermediate.

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.
NYMEX	New York Mercantile Exchange.
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.
SEC	United States Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this 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 recently completed drop-down acquisition and our pending Santa Elena acquisition described in this report and our other 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.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Viper Energy Partners LP
Consolidated Balance Sheets
(Unaudited)

	September 30, 2019	December 31, 2018
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 19,952	$ 22,676
Royalty income receivable	43,288	38,823
Royalty income receivable—related party	14,033	3,489
Other current assets	252	257
Total current assets	77,525	65,245
Property:		
Oil and natural gas interests, full cost method of accounting ($1,051,791 and $871,485 excluded from depletion at September 30, 2019 and December 31, 2018, respectively)	2,036,561	1,716,713
Land	5,688	5,688
Accumulated depletion and impairment	(299,704)	(248,296)
Property, net	1,742,545	1,474,105
Funds held in escrow	7,500	—
Deferred tax asset	157,885	96,883
Other assets	21,483	17,831
Total assets	$ 2,006,938	$ 1,654,064
Liabilities and Unitholders' Equity		
Current liabilities:		
Other accrued liabilities	$ 5,370	$ 6,022
Total current liabilities	5,370	6,022
Long-term debt	409,500	411,000
Total liabilities	414,870	417,022
Commitments and contingencies (Note 13)		
Unitholders' equity:		
General partner	1,000	1,000
Common units (62,649,348 units issued and outstanding as of September 30, 2019 and 51,653,956 units issued and outstanding as of December 31, 2018)	774,815	540,112
Class B units (72,418,500 units issued and outstanding as of September 30, 2019 and December 31, 2018)	990	990
Total Viper Energy Partners LP unitholders' equity	776,805	542,102
Non-controlling interest	815,263	694,940
Total equity	1,592,068	1,237,042
Total liabilities and unitholders' equity	$ 2,006,938	$ 1,654,064

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$ 71,080	$ 73,497	$ 201,950	$ 209,902
Lease bonus income	698	4,205	3,607	5,133
Other operating income	10	12	15	120
Total operating income	71,788	77,714	205,572	215,155
Costs and expenses:				
Production and ad valorem taxes	4,731	5,027	12,812	14,133
Depletion	18,697	16,532	51,408	41,317
General and administrative expenses	1,805	1,309	5,223	6,230
Total costs and expenses	25,233	22,868	69,443	61,680
Income from operations	46,555	54,846	136,129	153,475
Other income (expense):				
Interest expense, net	(3,827)	(3,711)	(11,089)	(9,061)
Gain (loss) on revaluation of investment	336	(199)	3,978	5,165
Other income, net	553	640	1,756	1,479
Total other expense, net	(2,938)	(3,270)	(5,355)	(2,417)
Income before income taxes	43,617	51,576	130,774	151,058
Provision for (benefit from) income taxes	(7,480)	764	(41,908)	(71,114)
Net income	51,097	50,812	172,682	222,172
Net income attributable to non-controlling interest	43,151	48,466	128,692	77,526
Net income attributable to Viper Energy Partners LP	$ 7,946	$ 2,346	$ 43,990	$ 144,646
Net income attributable to common limited partners per unit:				
Basic	$ 0.13	$ 0.05	$ 0.73	$ 1.85
Diluted	$ 0.13	$ 0.05	$ 0.73	$ 1.85
Weighted average number of common limited partner units outstanding:				
Basic	62,645	48,234	60,267	78,250
Diluted	62,678	48,304	60,296	78,319

See accompanying notes to consolidated financial statements.

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, 2018	51,654	$ 540,112	72,419	$ 990	$ 1,000	$ 694,940	$ 1,237,042
Net proceeds from the issuance of common units - public	10,925	340,648		—	—	—	340,648
Unit-based compensation	60	405		—	—	—	405
Distributions to public		(25,970)		—	—	—	(25,970)
Distributions to Diamondback		(392)		—	—	(36,934)	(37,326)
Distributions to General Partner		(20)		—	—	—	(20)
Change in ownership of consolidated subsidiaries, net		(71,195)		—	—	90,120	18,925
Units repurchased for tax withholding	(11)	(353)		—	—	—	(353)
Net income		33,779		—	—	40,532	74,311
Balance at March 31, 2019	62,628	817,014	72,419	990	1,000	788,658	1,607,662
Offering costs		(9)		—	—	—	(9)
Unit-based compensation		472		—	—	—	472
Distributions to public		(23,521)		—	—	—	(23,521)
Distributions to Diamondback		(298)		—	—	(27,519)	(27,817)
Distributions to General Partner		(20)		—	—	—	(20)
Net income		2,265		—	—	45,009	47,274
Balance at June 30, 2019	62,628	795,903	72,419	990	1,000	806,148	1,604,041
Unit-based compensation	21	449		—	—	—	449
Distributions to public		(29,099)		—	—	—	(29,099)
Distributions to Diamondback		(364)		—	—	(34,036)	(34,400)
Distributions to General Partner		(20)		—	—	—	(20)
Net income		7,946		—	—	43,151	51,097
Balance at September 30, 2019	62,649	$ 774,815	72,419	$ 990	$ 1,000	$ 815,263	$ 1,592,068

See accompanying notes to consolidated financial statements.

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

	Limited Partners				General Partner	Non-Controlling Interest	
	Common Units	Amount	Class B Units	Amount	Amount	Amount	Total
				(In thousands)			
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-based compensation		1,288		—	—	—	1,288
Distributions to public		(18,737)		—	—	—	(18,737)
Distributions to Diamondback		(33,649)		—	—	—	(33,649)
Net income		42,896		—	—	—	42,896
Balance at March 31, 2018	113,882	887,055	—	—	—	—	887,055
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)
Unit-based compensation	7	452		—	—	—	452
Distributions to public		(19,551)		—	—	—	(19,551)
Distributions to Diamondback		(35,112)		—	—	—	(35,112)
Net income		99,404		—	—	29,060	128,464
Balance at June 30, 2018	41,471	386,807	72,419	990	1,000	574,501	963,298
Net proceeds from the issuance of common units - public	10,080	305,773		—	—	—	305,773
Offering Costs		(2,636)		—	—	—	(2,636)
Unit-based compensation	96	426		—	—	—	426
Unit options exercised	8	140		—	—	—	140
Distributions to public		(30,501)		—	—	—	(30,501)
Distributions to Diamondback		(450)		—	—	(43,451)	(43,901)
Distributions to General Partner		(11)		—	—	—	(11)
Change in ownership of consolidated subsidiaries, net		(91,667)		—	—	116,034	24,367
Net income		2,346		—	—	48,466	50,812
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.

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

	Nine Months Ended September 30,	
	2019	2018
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 172,682	$ 222,172
Adjustments to reconcile net income to net cash provided by operating activities:		
Benefit from deferred income taxes	(42,077)	(71,184)
Depletion	51,408	41,317
Gain on revaluation of investment	(3,978)	(5,165)
Amortization of debt issuance costs	676	521
Non-cash unit-based compensation	1,326	2,166
Changes in operating assets and liabilities:		
Royalty income receivable	(4,465)	(12,264)
Royalty income receivable—related party	(10,544)	(2,616)
Accounts payable and other accrued liabilities	(821)	1,315
Income tax payable	169	69
Other current assets	(148)	83
Net cash provided by operating activities	164,228	176,414
Cash flows from investing activities:		
Acquisition of oil and natural gas interests	(319,696)	(505,842)
Other	—	(4,687)
Funds held in escrow	(7,500)	—
Proceeds from sale of assets	—	441
Proceeds from the sale of investments	—	124
Net cash used in investing activities	(327,196)	(509,964)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	368,000	557,000
Repayment on credit facility	(369,500)	(354,000)
Debt issuance costs	(349)	(623)
Proceeds from public offerings	340,860	305,773
Public offering costs	(221)	(2,636)
Proceeds from exercise of unit options	—	140
Contributions by members	—	2,000
Units purchased for tax withholding	(353)	—
Distributions to partners	(178,193)	(181,472)
Net cash provided by financing activities	160,244	326,182
Net decrease in cash	(2,724)	(7,368)
Cash and cash equivalents at beginning of period	22,676	24,197
Cash and cash equivalents at end of period	$ 19,952	$ 16,829
Supplemental disclosure of cash flow information:		
Interest paid	$ 10,882	$ 8,147

See accompanying notes to consolidated financial statements.

Viper Energy Partners LP
Condensed Notes to Consolidated Financial Statements
(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

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

As of September 30, 2019, Viper Energy Partners GP LLC (the "General Partner"), held a 100% general partner interest in the Partnership and Diamondback had an approximate 54% limited partner interest in the Partnership. Diamondback owns and controls the General Partner. Immediately following the completion of the Drop-Down Acquisition on October 1, 2019, Diamondback owned 731,500 common units and 90,709,946 Class B units, representing approximately 60% of the Partnership's total units outstanding. See Note 4—Acquisitions and Note 14—Subsequent Events for additional information regarding this transaction.

Recapitalization, Tax Status Election and Related Transactions

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

On May 10, 2018, the change in the Partnership's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) Diamondback made a cash capital contribution of $1.0 million to the Partnership in respect of the Class B units. Diamondback, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, Diamondback also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as the Partnership's general partner and Diamondback continues to control the Partnership. After the effectiveness of the tax status election and the completion of related transactions, the Partnership's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure 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. 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, 2018, 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 was accounted for under the cost method. This investment is presented on the balance sheet as other long-term assets. Effective January 1, 2018, the Partnership adopted Accounting Standards Update ("ASU") 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. See Note 12—Fair Value Measurements for additional disclosure regarding the impact of the fair value measurement of this investment.

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—Related Party Transactions. In addition to the 2018 tax year, the Partnership's 2016 and 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, 2019, 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 three and nine months ended September 30, 2019, 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 February 2016, the Financial Accounting Standards Board ("FASB") issued ASU 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 was effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities were required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. As of September 30, 2019, the Partnership was not the lessor or lessee of any leases other than mineral leases which were excluded from the scope of this ASU. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In January 2018, the FASB issued ASU 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 adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In July 2018, the FASB issued ASU 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 was effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In July 2018, the FASB issued ASU 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 was effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In December 2018, the FASB issued ASU 2018-20, "Leases (Topic 842) - Narrow-Scope Improvements for Lessors". This update provides a practical expedient for lessors to elect not to evaluate whether sales taxes and other similar taxes are lessor costs. The update also requires a lessor to exclude from variable payments those costs paid directly by the lessee to third parties and include lessor costs paid by the lessor and reimbursed by the lessee. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In January 2019, the FASB issued ASU 2019-01, "Leases (Topic 842): Codification Improvements". This update clarifies certain presentation and transition disclosures under Topic 842. This update was effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In June 2018, the FASB issued ASU 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 was effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In July 2018, the FASB issued ASU 2018-09, “Codification Improvements”. This update provides clarification and corrects unintended application of the guidance in various sections. This update was effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership adopted this update effective January 1, 2019. It did not have a material impact on its financial position, results of operations or liquidity.

In July 2019, the FASB issued ASU 2019-07, “Codification Updates to SEC Sections”. This update simplifies the guidance in various sections that was duplicative, redundant or outdated. The Partnership adopted this update effective July 2019. It did not have a material impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In June 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses”. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. 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 November 2018, the FASB issued ASU 2018-19, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses”. This update clarifies that receivables arising from operating leases are not in scope of this topic, but rather Topic 842, Leases. 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 April 2019, the FASB issued ASU 2019-04, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives and Hedging, and Topic 825, Financial Instruments”. This update clarifies guidance previously issued in ASU 2016-01, ASU 2016-13 and ASU 2017-12. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Partnership does not believe the updates to the referenced standards will have an impact on its financial position, results of operations or liquidity.

In May 2019, the FASB issued ASU 2019-05, “Financial Instruments-Credit Losses (Topic 326)”. This update allows a fair value option to be elected for certain financial assets, other than held-to-maturity debt securities, that were previously required to be measured at amortized cost basis. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Partnership does not believe the adoption of this standard will have an impact on its financial position, results of operations or liquidity.

In August 2018, the FASB issued ASU 2018-13, “Fair Value Measurement (Topic 820) - Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement”. This update modifies the fair value measurement disclosure requirements specifically related to Level 3 fair value measurements and transfers between levels. 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 prospectively. The Partnership does not believe the adoption of this standard will have an impact on its financial position, results of operations or liquidity.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Effective January 1, 2018, the Partnership adopted the FASB ASU 2014-09, “Revenue from Contracts with Customers” using the modified retrospective method. The adoption of this standard did not result in a cumulative-effect adjustment.

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 or operator at the wellhead or at the gas processing facility based on the Partnership's percentage ownership share of the revenue, net any deductions for gathering and transportation.

Transaction price allocated to remaining performance obligations

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

Contract balances

Under the Partnership's royalty income contracts, it would have the right to receive royalty income 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. 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, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Partnership believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the royalties related to expected sales volumes and prices for those properties are estimated and recorded.

4. ACQUISITIONS

2019 Activity

Drop-Down Acquisition

On July 29, 2019, the Partnership entered into a definitive purchase agreement to acquire certain mineral and royalty interests from subsidiaries of Diamondback for approximately 18.3 million of its newly-issued Class B units, approximately 18.3 million newly-issued units of the Operating Company and $190.2 million in cash, after giving effect to closing adjustments for net title benefits (the ‘‘Drop-Down Acquisition’’). Based on the volume weighted average sales price of our common units for the ten trading-day period ended July 26, 2019 of $30.07, the transaction is valued at $740.2 million. The mineral and royalty interests acquired in the Drop-Down Acquisition represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by Diamondback, and have an average net royalty interest of approximately 3.2% (the ‘‘Drop-Down Assets’’). The Drop-Down Assets are concentrated in Diamondback's seven core operating areas, with the largest exposure to Spanish Trail North, where Diamondback is currently running two rigs, as well as Pecos County, where Diamondback is currently running six rigs. The Partnership completed the acquisition on October 1, 2019 and funded the cash portion of the purchase price for the Drop-Down Assets through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. In connection with the closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million.

Other Recent Acquisitions

In addition, during the three months ended September 30, 2019, the Partnership acquired, from unrelated third-party sellers, mineral interests representing 101,520 gross (1,281 net royalty) acres in the Permian Basin for an aggregate of approximately $193.6 million, subject to post-closing adjustments. These acquisitions were funded with cash on hand and borrowings under the Operating Company's revolving credit facility.

During the nine months ended September 30, 2019, the Partnership acquired, from unrelated third parties, mineral interests underlying 2,309 net royalty acres for an aggregate purchase price of approximately $320.5 million and, as of September 30, 2019, had mineral interests underlying 17,151 net royalty acres. The Partnership funded these acquisitions with cash on hand, a portion of the net proceeds from its first quarter 2019 offering of common units and borrowings under the Operating Company's revolving credit facility.

As a result of the Drop-Down Acquisition and the other recently completed acquisitions described above (collectively, the ‘‘Recent Acquisitions’’), as of October 15, 2019, the Partnership's assets included mineral interests representing 22,641 net royalty acres in the Permian Basin and the Eagle Ford Shale, 51% of which are operated by Diamondback.

Pending Santa Elena Acquisition

On September 9, 2019, the Partnership and the Operating Company entered into a definitive purchase and sale agreement (the ‘‘Santa Elena Purchase and Sale Agreement’’) with Santa Elena Minerals, LP, an unrelated third-party seller (‘‘Santa Elena’’), providing for an acquisition by the Partnership of certain mineral and royalty interests from Santa Elena (the ‘‘Pending Santa Elena Acquisition’’), which assets will be immediately contributed by the Partnership to the Operating Company at closing of the Pending Santa Elena Acquisition. The assets being acquired in the Pending Santa Elena Acquisition represent approximately 1,358 net royalty acres across the Midland Basin with an average net royalty interest of approximately 5.6% and are primarily operated by Diamondback in Glasscock and Martin counties (the ‘‘Santa Elena Assets’’). The Pending Santa Elena Acquisition is expected to close on October 31, 2019, subject to the completion of due diligence and the satisfaction of customary closing conditions, and will have an effective date of October 1, 2019.

At closing, the Partnership will issue to Santa Elena common units representing limited partner interests in the Partnership as consideration for the Santa Elena Assets, and the Operating Company will issue to the Partnership new units of the Operating Company, in each case in a number equal to the quotient of (a) $150.0 million (as adjusted pursuant to the Santa Elena Purchase and Sale Agreement) divided by (b) $29.02, which represents the volume weighted average sale prices as traded on Nasdaq of the Partnership's common units calculated for the five trading-day period ended September 5, 2019. Assuming no adjustments to the purchase price, Santa Elena would receive approximately 5.2 million common units. With respect to the common units it receives under the Santa Elena Purchase and Sale Agreement, Santa Elena has agreed to waive its right to receive any distributions for which the record date falls in the fourth quarter of 2019.

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.

5. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	September 30, 2019	December 31, 2018
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$ 984,770	$ 845,228
Not subject to depletion	1,051,791	871,485
Gross oil and natural gas interests	2,036,561	1,716,713
Accumulated depletion and impairment	(299,704)	(248,296)
Oil and natural gas interests, net	1,736,857	1,468,417
Land	5,688	5,688
Property, net of accumulated depletion and impairment	$ 1,742,545	$ 1,474,105
Balance of costs not subject to depletion:		
Incurred in 2019	$ 267,930	
Incurred in 2018	462,630	
Incurred in 2017	284,371	
Incurred in 2016	36,860	
Total not subject to depletion	$ 1,051,791	

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 years to five years.

Under the full cost method of accounting, the Partnership is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and 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 revenue including estimated expenditures (based on current costs) to be incurred in developing and producing the proved reserves, 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

The Operating Company's Revolving Credit Facility

On July 20, 2018, the Partnership, as guarantor, entered into an amended and restated credit agreement with the Operating Company, as borrower, Wells Fargo National Bank ("Wells Fargo"), as administrative agent, and the other lenders. The credit agreement, as amended to the date hereof, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on the Operating Company's oil and natural gas reserves and other factors (the ''borrowing base'') of $725.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. Upon closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million. In connection with the commencement of the Notes Offering described in Note 14—Subsequent Events below, the Partnership entered into a third amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provides for the waiver of the automatic reduction of the borrowing base that would otherwise occur upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or the Partnership from $400.0 million to $1.0 billion. The amendment was approved by the requisite percentage of lenders under the revolving credit facility and became effective on October 8, 2019. If the amendment had not been approved, the borrowing base under the revolving credit facility would have decreased by $125.0 million upon consummation of the Notes Offering.

As of September 30, 2019, when the borrowing base was set at $600.0 million, the Operating Company had $409.5 million of outstanding borrowings and $190.5 million available for future borrowings under the Operating Company's revolving credit facility. The Partnership funded the cash portion of the purchase price for the Drop-Down Acquisition through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility. Following these transactions, as of October 16, 2019, the closing date of the Notes Offering, there was $94.5 million in outstanding borrowings under the Operating Company's revolving credit facility, the borrowing base under the Operating Company's revolving credit facility was $725.0 million, and the Operating Company had $630.5 million of available borrowing capacity under the Operating Company's revolving credit facility. Additionally, in connection with the Partnership's fall redetermination expected to occur in November 2019, the lead bank under the Operating Company's revolving credit facility has recommended a borrowing base increase to $775.0 million from the current borrowing base of $725.0 million. The anticipated increase in the borrowing base is subject to approval by the requisite lenders under the Operating Company's revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Operating Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of 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, 2019, 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 months ended September 30, 2019 and 2018, the General Partner allocated $0.9 million and $0.6 million, respectively, to the Partnership. For the nine months ended September 30, 2019 and 2018, the General Partner allocated $2.2 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 provided the Partnership and the General Partner with general financial and strategic advisory services related to the Partnership’s business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement was terminated on November 12, 2018 and the Partnership’s payment obligation ended in June 2019. During 2019, the Partnership did not pay any amounts under the Advisory Services Agreement. For the three and nine months ended September 30, 2018, 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 months ended September 30, 2019 and 2018, the Partnership accrued state income tax expense (benefit) of less than $0.1 million and $(0.1) million, respectively, and for the nine months ended September 30, 2019 and 2018, the Partnership accrued state income tax expense of $0.2 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 months ended September 30, 2019, Diamondback did not pay the Partnership any lease bonus payments. During the nine months ended September 30, 2019, Diamondback paid the Partnership $39,198 in lease bonus payments to extend the term of two leases and $3,101 in lease bonus payments for two new leases. 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.

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, 2019, a total of 8,922,726 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, 2019, the Partnership incurred $0.4 million and $1.3 million, respectively, of unit–based compensation.

Phantom Units

Under the LTIP, the board of directors of the General Partner is authorized to issue phantom units to eligible employees 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, 2019:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	125,053	$ 23.44
Granted	33,886	$ 32.78
Vested	(81,124)	$ 23.34
Forfeited	(1,028)	$ 42.50
Unvested at September 30, 2019	76,787	$ 27.42

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2019 was $1.9 million. As of September 30, 2019, the unrecognized compensation cost related to unvested phantom units was $1.3 million. Such cost is expected to be recognized over a weighted-average period of 0.81 years.

9. UNITHOLDERS' EQUITY AND PARTNERSHIP DISTRIBUTIONS

The Partnership has general partner and limited partner units. At September 30, 2019, the Partnership had a total of 62,649,348 common units issued and outstanding and 72,418,500 Class B units issued and outstanding, of which 731,500 common units and 72,418,500 Class B units were owned by Diamondback, representing approximately 54% of the total Partnership's units outstanding. The Operating Company units and the Partnership's Class B units owned by Diamondback are exchangeable from time to time for the Partnership's common units (that is, one Operating Company unit and one Partnership Class B unit, together, will be exchangeable for one Partnership common unit).

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

	Common Units
Balance at December 31, 2018	51,653,956
Common units issued in public offerings	10,925,000
Common units vested and issued under the LTIP	81,124
Units repurchased for tax withholding	(10,732)
Balance at September 30, 2019	62,649,348

The Partnership had a total of 72,418,500 Class B units outstanding as of September 30, 2019 and December 31, 2018, respectively.

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

The board of directors of the General Partner has adopted a policy for the Partnership to distribute on a quarterly basis all available cash it receives from the Operating Company.

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 2018	$ 0.51	January 30, 2019	February 19, 2019	February 25, 2019
Q1 2019	$ 0.38	April 25, 2019	May 13, 2019	May 20, 2019
Q2 2019	$ 0.47	July 28, 2019	August 14, 2019	August 21, 2019

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, 2019 and 2018, 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(In thousands, except per unit amounts)			
Net income attributable to the period	$ 7,946	$ 2,346	$ 43,990	$ 144,646
Weighted average common units outstanding:				
Basic weighted average common units outstanding	62,645	48,234	60,267	78,250
Effect of dilutive securities:				
Potential common units issuable	33	70	29	69
Diluted weighted average common units outstanding	62,678	48,304	60,296	78,319
Net income per common unit, basic	$ 0.13	$ 0.05	$ 0.73	$ 1.85
Net income per common unit, diluted	$ 0.13	$ 0.05	$ 0.73	$ 1.85

For the three months ended September 30, 2019 and 2018, there were no common units and for nine months ended September 30, 2019 and 2018, there were no common units and 1,092 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—Organization and Basis of Presentation, on March 29, 2018, the Partnership announced that the Board of Directors of the General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. Subsequent to the Partnership's change in tax status, the Partnership's provision for income taxes for the period ended September 30, 2019 is based on the estimated annual effective tax rate plus discrete items.

The Partnership's effective income tax rates were (17.1)% and 1.5% for the three months ended September 30, 2019 and 2018, respectively, and (32.05)% and (47.10)% for the nine months ended September 30, 2019 and 2018, respectively. Total income tax benefit for the three and nine months ended September 30, 2019 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to net income attributable to the non-controlling interest and the revision of estimated deferred taxes recognized as a result of the Partnership's change in tax status. Total income tax expense for the three months ended September 30, 2018 and total income tax benefit for the nine months ended September 30, 2018 September 30, 2018 differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to (i) net income attributable to the non-controlling interest (ii) net income attributable to the period prior to the Partnership's change in tax status, and (iii) for the nine months ended September 30, 2018, the impact of deferred taxes recognized as a result of the Partnership's change in tax status.

For the nine months ended September 30, 2019, the Partnership recorded a discrete income tax benefit of approximately $42.4 million related to the revision of estimated deferred taxes on the Partnership's investment in the Operating Company arising from the change in the Partnership's federal tax status. Under federal income tax provisions applicable to the Partnership's change in tax status, the Partnership's basis for federal income tax purposes in its interest in the Operating Company consists primarily of the sum of the Partnership's unitholders' tax bases in their interests in the Partnership on the date of the tax status change. The Partnership prepared its best estimate of the resultant tax basis in the Operating Company for purposes of the Partnership's income tax provision for the period of the change, but information necessary for the partnership to finalize its determination was not available until unitholders' tax basis information was fully reported and the Partnership finalized its federal income tax computations for 2018. Based on such finalized information, the Partnership has revised its estimate of the difference between its tax basis and its basis for financial accounting purposes in the Operating Company on the date of the tax status change, resulting in deferred income tax benefit of $42.4 million included in the Partnership's income tax provision for the nine months ended September 30, 2019.

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. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

The Partnership's cost method investment is reported at fair value on a recurring basis. The fair value of the Partnership's investment at September 30, 2019 and December 31, 2018 was determined using the September 30, 2019 and December 31, 2018 quoted market prices. The investment is a Level 1 classification in the fair value hierarchy. See Note 2—Summary of Significant Accounting Policies. The following table summarizes the changes in fair value of the Partnership's investment:

	(in thousands)
Fair value of investment as of December 31, 2018	$ 14,525
Gain on investment	3,978
Fair value of investment as of September 30, 2019	$ 18,503

	(in thousands)
Fair value of investment as of December 31, 2017	$ 33,851
Impact of adoption of Accounting Standards Update 2016-01	(18,651)
Gain on investment	5,165
Fair value of investment as of September 30, 2018	$ 20,365

13. COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various legal proceedings, disputes and claims from time to time arising in the course of its business, including those that arise from interpretation of federal and state laws and regulations affecting the crude oil and natural gas industry. These proceedings, disputes and claims may include differing interpretations as to the prices at which crude oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, title claims, environmental issues and other matters. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on the Partnership, cannot be predicted with certainty, the Partnership believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Partnership's financial condition, cash flows or results of operations. The Partnership's assessment is based on information known about the pending matters and its experience in contesting, litigating and settling similar matters. Actual outcomes could differ materially from the Partnership's assessment. The Partnership records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

14. SUBSEQUENT EVENTS

Cash Distribution

On October 25, 2019, the board of directors of the General Partner approved a cash distribution for the third quarter of 2019 of $0.46 per common unit, payable on November 15, 2019, to eligible unitholders of record at the close of business on November 8, 2019. Diamondback received Class B units and units in the Operating Company upon the closing of the Drop-Down Acquisition on October 1, 2019 and the Partnership will issue common units to Santa Elena at the closing of the Pending Santa Elena Acquisition. Each of Diamondback and Santa Elena has waived its right to receive distributions for the third quarter of 2019 in respect of the applicable equity interests issued in these transactions and the cash distribution for the third quarter of 2019 has been calculated on this basis.

Drop-Down Acquisition

On October 1, 2019, the Partnership completed the acquisition of certain mineral and royalty interests from subsidiaries of Diamondback for approximately 18.3 million of the Partnership's newly-issued Class B units, approximately 18.3 million newly-issued units of the Operating Company and $190.2 million in cash, after giving effect to closing adjustments for net title benefits. For a description of the Drop-Down Acquisition, see Note 4—Acquisitions—Drop-Down Acquisition above.

Pending Santa Elena Acquisition

On September 9, 2019, the Partnership and the Operating Company entered into a definitive purchase and sale agreement with Santa Elena, providing for an acquisition by the Partnership of certain mineral and royalty interests from Santa Elena which assets will be immediately contributed by the Partnership to the Operating Company at closing of the Pending Santa Elena Acquisition. For a description of the Pending Santa Elena Acquisition, see Note 4—Acquisitions—Pending Santa Elena Acquisition above.

Notes Offering

On October 16, 2019, the Partnership completed an offering (the "Notes Offering") of $500.0 million in aggregate principal amount of its 5.375% Senior Notes due 2027 (the "Notes"). The Partnership received net proceeds of approximately $492.0 million from the Notes Offering. The Partnership loaned the gross proceeds to the Operating Company. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility.

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

Amendments to the Operating Company's Revolving Credit Facility

As described above, on September 24, 2019, the Partnership entered into a second amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provided for an automatic increase of the borrowing base of $125.0 million upon the closing of the Drop-Down Acquisition and the satisfaction of certain conditions set forth therein. On October 1, 2019, upon closing of the Drop-Down Acquisition and the satisfaction of such conditions, the borrowing base was increased from $600.0 million to $725.0 million.

In connection with the commencement of the Notes Offering, the Partnership entered into a third amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provides for the waiver of the automatic reduction of the borrowing base that would otherwise occur upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or the Partnership from $400.0 million to $1.0 billion. The amendment was approved by the requisite percentage of lenders under the revolving credit facility and became effective on October 8, 2019. If the amendment had not been approved, the borrowing base under the revolving credit facility would have decreased by $125.0 million upon consummation of the Notes Offering.

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

In connection with the Partnership's fall redetermination expected to occur in November 2019, the lead bank under the Operating Company's revolving credit facility has recommended a further borrowing base increase to $775.0 million from the current borrowing base of $725.0 million. The anticipated increase in the borrowing base is subject to approval by the requisite lenders under the Operating Company's revolving credit facility.

Intercompany Promissory Note

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

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

As of September 30, 2019, 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 54% of our total units outstanding. On October 1, 2019, immediately following the completion of the Drop-Down Acquisition, Diamondback owned 731,500 common units and 90,709,946 Class B units, representing approximately 60% of our total units outstanding. See "Recent Developments—Drop-Down Acquisition" below. 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,	
	2019	2018	2019	2018
Operating income:				
Royalty income:				
Oil sales	90%	82%	89%	86%
Natural gas sales	3%	5%	2%	4%
Natural gas liquid sales	6%	8%	7%	8%
Lease bonus income	1%	5%	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.

The following table sets forth information related to commodity prices for the following periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
High and Low Futures Contract Prices:				
Oil ($/Bbl, WTI Futures Contract 1)				
High	$ 62.90	$ 74.14	$ 66.30	$ 74.15
Low	$ 51.09	$ 65.01	$ 46.54	$ 59.19
Natural Gas ($/MMBtu, Futures Contract 1)				
High	$ 2.68	$ 3.08	$ 3.59	$ 3.63
Low	$ 2.07	$ 2.72	$ 2.07	$ 2.55

On September 30, 2019, the WTI Futures Contract 1 price for crude oil was $54.07 per Bbl and the Natural Gas Futures Contract 1 price was $2.33 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 Developments

Drop-Down Acquisition

On October 1, 2019, we completed the acquisition of certain mineral and royalty interests from subsidiaries of Diamondback for approximately 18.3 million of our newly-issued Class B units, approximately 18.3 million newly-issued units of the Operating Company and $190.2 million in cash, after giving effect to closing adjustments for net title benefits, which we refer to as the Drop-Down Acquisition. Based on the volume weighted average sales price of our common units for the ten trading-day period ended July 26, 2019 of $30.07, the transaction is valued at $740.2 million. The mineral and royalty interests acquired in the Drop-Down Acquisition represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by Diamondback, and have an average net royalty interest of approximately 3.2%, which we refer to as the Drop-Down Assets. The Drop-Down Assets are concentrated in Diamondback's seven core operating areas, with the largest exposure to Spanish Trail North, where Diamondback is currently running two rigs, as well as Pecos County, where Diamondback is currently running six rigs. We funded the cash portion of the purchase price for the Drop-Down Assets through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. In connection with the closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million.

Other Recent Acquisitions

In addition, during the third quarter of 2019, we acquired from unrelated third-party sellers mineral interests representing 101,520 gross (1,281 net royalty) acres in the Permian Basin for an aggregate of approximately $193.6 million, subject to post-closing adjustments. These acquisitions were funded with cash on hand and borrowings under the Operating Company's revolving credit facility.

During the nine months ended September 30, 2019, we acquired, from unrelated third parties, 2,309 net royalty acres for an aggregate purchase price of $320.5 million, subject to post-closing adjustments, bringing our total mineral interests to 17,151 net royalty acres as of September 30, 2019. We funded these acquisitions with cash on hand, a portion of the net proceeds from our first quarter 2019 offering of common units and borrowings under our revolving credit facility.

As a result of the Drop-Down Acquisition and the other recently completed acquisitions described above, which we collectively refer to as the Recent Acquisitions, as of October 15, 2019, our assets included mineral interests representing 22,641 net royalty acres in the Permian Basin and the Eagle Ford Shale, 51% of which are operated by Diamondback.

Pending Santa Elena Acquisition

On September 9, 2019, we and the Operating Company entered into a definitive purchase and sale agreement, which we refer to as the Santa Elena Purchase and Sale Agreement, with Santa Elena Minerals, LP, an unrelated third-party seller, or Santa Elena, providing for an acquisition by us of certain mineral and royalty interests from Santa Elena, which we refer to as the Pending Santa Elena Acquisition, which assets will be immediately contributed by us to the Operating Company at closing of the Pending Santa Elena Acquisition. The assets being acquired in the Pending Santa Elena Acquisition represent approximately 1,358 net royalty acres across the Midland Basin with an average net royalty interest of approximately 5.6% and are primarily operated by Diamondback in Glasscock and Martin counties, which we refer to as the Santa Elena Assets. The Pending Santa Elena Acquisition is expected to close on October 31, 2019, subject to the completion of due diligence and the satisfaction of customary closing conditions, and will have an effective date of October 1, 2019.

At closing, we will issue to Santa Elena common units representing limited partner interests in us as consideration for the Santa Elena Assets, and the Operating Company will issue to us new units of the Operating Company, in each case in a number equal to the quotient of (a) $150.0 million (as adjusted pursuant to the Santa Elena Purchase and Sale Agreement) divided by (b) $29.02, which represents the volume weighted average sale prices as traded on Nasdaq of our common units calculated for the five trading-day period ended September 5, 2019. Assuming no adjustments to the purchase price, Santa Elena would receive approximately 5.2 million common units. With respect to the common units it receives under the Santa Elena Purchase and Sale Agreement, Santa Elena has agreed to waive its right to receive any distributions for which the record date falls in the fourth quarter of 2019.

Estimated Pro Forma Acreage and Reserves

After giving pro forma effect to the Drop-Down Acquisition and the Pending Santa Elena Acquisition, our mineral interests at September 30, 2019 would have totaled 23,999 net royalty acres primarily in the Permian Basin and the Eagle Ford Shale, 51% of which are operated by Diamondback. As of October 15, 2019, there were approximately 445 gross horizontal wells in the process of development on our pro forma asset base, in which we expect to own an average 1.9% net royalty interest (8.6 net 100% royalty wells). These wells currently in the process of active development include various wells currently being drilled by the 57 active rigs which were on our acreage as of October 15, 2019, in addition to other wells currently waiting to be completed, actively in the process of being completed or waiting to be turned to production. Additionally, based on Diamondback's current completion schedule and third party operators' permits, we believe that a further 326 gross (9.3 net 100% royalty interest) wells with an average royalty interest of 2.8%, for which the process of active development has not yet begun, will be turned to production within the next 12 months.

After giving pro forma effect to the Recent Acquisitions and the Pending Santa Elena Acquisition, as of December 31, 2018, (1) our estimated proved developed reserves as of December 31, 2018 would have increased from 29,526 MBbls to 37,621 MBbls of oil, from 49,681 MMcf to 67,801 MMcf of natural gas and from 7,965 MBbls to 11,333 MBbls of natural gas liquids, for a total increase from 45,771 MBOE to 60,254 MBOE, (2) our estimated proved undeveloped reserves would have increased from 12,352 MBbls to 14,172 MBbls of oil, from 11,916 MMcf to 14,875 MMcf of natural gas and from 3,027 MBbls to 3,738 MBbls of natural gas liquids, for a total increase from 17,365 MBOE to 20,389 MBOE and (3) our estimated net proved reserves would have increased from 41,878 MBbls to 51,793 MBbls of oil, from 61,597 MMcf to 82,675 MMcf of natural gas and from 10,992 MBbls to 15,071 MBbls of natural gas liquids, for a total increase from 63,136 MBOE to 80,643 MBOE. These estimates are based on a reserve report prepared by Ryder Scott as of December 31, 2018 with respect to our year end reserves and with respect to the Diamondback-operated reserves we acquired in the Drop-Down Acquisition and will acquire in the Pending Santa Elena Acquisition, each dated as of December 31, 2018.

The pro forma information presented above is based solely on our internal evaluation and interpretation of reserve, production and other information provided to us by our counterparties in the course of our due diligence with respect to the Recent Acquisitions and the Pending Santa Elena Acquisition and has not been independently verified or estimated and has not been reviewed by our auditors. These pro forma amounts are based on various assumptions, including, among others, the level of Diamondback's (and our other operators') capital spending, commodity prices, rig availability, services availability, proppant availability, takeaway capacity as well as other factors. To the extent any of these factors change, such changes could be material and these estimates may not be or may not have been achieved. Our actual operating results and financial condition may differ and could have differed materially from these estimates, and investors are cautioned not to place undue reliance on such pro forma information.

Amendments to the Operating Company's Revolving Credit Facility and Borrowing Base Increase

On September 24, 2019, we entered into a second amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provided for an automatic increase of the borrowing base of $125.0 million upon the closing of the Drop-Down Acquisition and the satisfaction of certain conditions set forth therein. On October 1, 2019, upon closing of the Drop-Down Acquisition and the satisfaction of such conditions, the borrowing base was increased from $600.0 million to $725.0 million.

On October 8, 2019, in connection with the commencement of the Notes Offering described below, we entered into a third amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provides for the waiver of the automatic reduction of the borrowing base that would otherwise occur upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or the Partnership from $400.0 million to $1.0 billion. The amendment was approved by the requisite percentage of lenders under the revolving credit facility and became effective on October 8, 2019. If the amendment had not been approved, the borrowing base under the revolving credit facility would have decreased by $125.0 million upon consummation of the Notes Offering.

In connection with our fall redetermination expected to occur in November 2019, the lead bank under the Operating Company's revolving credit facility has recommended a further borrowing base increase to $775.0 million from the current borrowing base of $725.0 million. The anticipated increase in the borrowing base is subject to approval by the requisite lenders under the Operating Company's revolving credit facility.

Notes Offering

On October 16, 2019, we completed an offering, which we refer to as the Notes Offering, of our 5.375% Senior Notes due 2027 in the aggregate principal amount of $500.0 million, which we refer to as the Notes. We received net proceeds of approximately $492.0 million from the Notes Offering. We loaned the gross proceeds of the Notes Offering to the Operating Company. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility. The Notes are our senior unsecured obligations and rank equally in right of payment with all of our existing and future senior indebtedness we may incur. The notes are initially fully and unconditionally guaranteed on a senior unsecured basis by the Operating Company. Neither Diamondback nor our general partner will guarantee the notes. In the future, each of our restricted subsidiaries that either (1) guarantees any of our or a guarantor's other indebtedness or (2) is a domestic restricted subsidiary and is an obligor with respect to any indebtedness under any credit facility will be required to guarantee the Notes.

Production and Operational Update

Our average daily production during the third quarter of 2019 was 21,266 BOE/d (64% oil), and our operators received an average of $51.53 per Bbl of oil, $9.84 per Bbl of natural gas liquids and $1.28 per Mcf of natural gas, for an average realized price of $36.33 per BOE. The average realized price of $1.28 per Mcf of natural gas was primarily due to the pricing terms under our operators' natural gas delivery contracts, which are generally tied to NYMEX price quoted at Henry Hub. Actual volumetric prices realized from the sale of natural gas, however, differ from the quoted NYMEX price as a result of quality and location differentials. During the third quarter, natural gas sold at the WAHA Hub in Pecos County, Texas averaged a differential of $(1.14) relative to the NYMEX price quoted at Henry Hub. Our operators may have varying terms under which they sell their natural gas, but we are mostly impacted by location differences resulting from supply and demand imbalances and limited takeaway capacity within the Permian Basin.

During the third quarter of 2019, we estimate that 171 gross (4.7 net 100% royalty interest) horizontal wells with an average royalty interest of 2.7% were turned to production on our existing acreage position with an average lateral length of 8,898 feet. Of these 171 gross wells, Diamondback is the operator of 41 with an average royalty interest of 8.1%, and the remaining 130 gross wells, which have an average royalty interest of 1.0%, are operated by third parties. Additionally, during the third quarter of 2019, we acquired 1,281 net royalty acres for an aggregate purchase price of approximately $193.6 million, which added a further 240 gross (1.9 net 100% royalty interest) producing horizontal wells with an average royalty interest of 0.8%. In total, as of September 30, 2019, we had 1,682 vertical wells and 3,166 horizontal wells producing on our acreage with a combined average net royalty interest of 3.6%. Despite a 20% decline in the Permian Basin rig count during the first nine months of 2019, there continues to be active development on our mineral acreage as represented by approximately 445 gross horizontal wells currently in the process of active development, in which we expect to own an average 1.9% net royalty interest (8.6 net 100% royalty interest). These wells currently in the process of active development include various wells currently being drilled by the 57 active rigs which were on our acreage as of October 15, 2019, in addition to other wells currently waiting to be completed, actively in the process of being completed or waiting to be turned to production. Additionally, based on Diamondback’s current completion schedule and third party operators’ permits, we believe that a further 326 gross (9.3 net 100% royalty interest) wells with an average royalty interest of 2.8%, for which the process or active development has not yet begun, will be turned to production within the next 12 months. Notwithstanding the foregoing, in the near-term, activity on our asset base is expected to be driven primarily by Diamondback’s operations as growth across the Permian Basin has slowed. As a result of this broad slowdown, as well as operators now preparing their budgets for 2020, there is currently less visibility into third party operators’ proposed activity levels and well completion cadence than in the previous quarters. Any slow-down in our operators’ proposed activity levels and completion schedule may have a negative impact on our estimated future net production and cash flows. Additionally, with respect to our estimated future net production, production from the assets acquired in the Recent Acquisitions and to be acquired in the Pending Santa Elena Acquisition will likely decline in the near-term relative to the production from the third quarter of 2019 for those same assets given the timing of completions on the acreage and associated flush production. However, we expect new flush production from completion activity on the acreage acquired in the Recent Acquisitions and the Pending Santa Elena Acquisition to resume in 2020.

Principal Components of Our Cost Structure

Production and Ad Valorem Taxes

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

General and Administrative

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

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. Subsequent to the Partnership’s change in tax status, we are subject to federal income taxes at the U.S. corporate statutory rate. The Partnership’s provision for income taxes is based on the estimated annual effective tax rate plus discrete items.

We are subject to the Texas margin tax. For the three months ended September 30, 2019 and 2018, we accrued less than $0.1 million and $(0.1) million, respectively, and for the nine months ended September 30, 2019 and 2018, we accrued $0.2 million and $0.1 million, respectively, for Texas margin tax payable pursuant to our tax sharing agreement with Diamondback.

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Operating Results:				
Operating income:				
Royalty income	$ 71,080	$ 73,497	$ 201,950	$ 209,902
Lease bonus income	698	4,205	3,607	5,133
Other operating income	10	12	15	120
Total operating income	71,788	77,714	205,572	215,155
Costs and expenses:				
Production and ad valorem taxes	4,731	5,027	12,812	14,133
Depletion	18,697	16,532	51,408	41,317
General and administrative expenses	1,805	1,309	5,223	6,230
Total costs and expenses	25,233	22,868	69,443	61,680
Income from operations	46,555	54,846	136,129	153,475
Other income (expense):				
Interest expense, net	(3,827)	(3,711)	(11,089)	(9,061)
Gain (loss) on revaluation of investment	336	(199)	3,978	5,165
Other income, net	553	640	1,756	1,479
Total other expense, net	(2,938)	(3,270)	(5,355)	(2,417)
Income before income taxes	43,617	51,576	130,774	151,058
Provision for (benefit from) income taxes	(7,480)	764	(41,908)	(71,114)
Net income	51,097	50,812	172,682	222,172
Net income attributable to non-controlling interest	43,151	48,466	128,692	77,526
Net income attributable to Viper Energy Partners LP	$ 7,946	$ 2,346	$ 43,990	$ 144,646

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Production Data:				
Oil (MBbls)	1,258	1,167	3,607	3,125
Natural gas (MMcf)	1,710	1,624	5,222	4,067
Natural gas liquids (MBbls)	413	254	976	645
Combined volumes (MBOE)	1,956	1,691	5,454	4,448
Daily combined volumes (BOE/d)	21,266	18,384	19,977	16,232
% Oil	64%	69%	66%	70%
Average sales prices:				
Oil ($/Bbl)	$ 51.53	$ 54.30	$ 50.65	$ 59.14
Natural gas ($/Mcf)(1)	$ 1.28	$ 2.22	$ 0.95	$ 2.14
Natural gas liquids ($/Bbl)	$ 9.84	$ 25.75	$ 14.67	$ 25.42
Combined ($/BOE)	$ 36.33	$ 43.45	$ 37.03	$ 47.19
Average Costs ($/BOE):				
Production and ad valorem taxes	$ 2.42	$ 2.97	$ 2.35	$ 3.18
General and administrative - cash component	0.69	0.52	0.71	0.91
Total operating expense - cash	$ 3.11	$ 3.49	$ 3.06	$ 4.09
General and administrative - non-cash component	$ 0.23	$ 0.25	$ 0.24	$ 0.49
Interest expense, net	$ 1.96	$ 2.19	$ 2.03	$ 2.04
Depletion	$ 9.56	$ 9.77	$ 9.43	$ 9.29

(1) The average realized price of $1.28 per Mcf of natural gas was primarily due to the pricing terms under our operators' natural gas delivery contracts, which are generally tied to NYMEX price quoted at Henry Hub. Actual volumetric prices realized from the sale of natural gas, however, differ from the quoted NYMEX price as a result of quality and location differentials. During the third quarter, natural gas sold at the WAHA Hub in Pecos County, Texas averaged a differential of $(1.14) relative to the NYMEX price quoted at Henry Hub. Our operators may have varying terms under which they sell their natural gas, but we are mostly impacted by location differences resulting from supply and demand imbalances and limited takeaway capacity within the Permian Basin.

Comparison of the Three Months Ended September 30, 2019 and 2018

Royalty Income

Our royalty income for the three months ended September 30, 2019 and 2018 was $71.1 million and $73.5 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

The decrease in average prices received during the three months ended September 30, 2019 as compared to the three months ended September 30, 2018 was partially offset by a 16% increase in combined volumes sold by our operators as compared to the three months ended September 30, 2018.

	Change in prices	Production volumes[(1)]	Total net dollar effect of change
			(in thousands)
Effect of changes in price:			
Oil	$ (2.77)	1,258	$ (3,483)
Natural gas	$ (0.94)	1,710	(1,612)
Natural gas liquids	$ (15.90)	413	(6,575)
Total income due to change in price			$ (11,670)

	Change in production volumes[(1)]	Prior period average prices	Total net dollar effect of change
			(in thousands)
Effect of changes in production volumes:			
Oil	91	$ 54.30	$ 4,957
Natural gas	86	$ 2.22	190
Natural gas liquids	159	$ 25.75	4,106
Total income due to change in production volumes			9,253
Total change in income			$ (2,417)

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

Realized pricing improved in the third quarter of 2019 compared to the second quarter of 2019 as some of Diamondback's fixed differential contracts began to roll off and convert to commitments on new-build long-haul pipelines and others moved closer to current Midland market price. Based on current market differentials and estimated in-basin gathering cost, we continue to expect to realize approximately 88% to 92% of WTI in the future remainder of 2019 and approximately 100% of WTI in 2020.

Lease Bonus Income

Lease bonus income decreased by $3.5 million for the three months ended September 30, 2019 as compared to the three months ended September 30, 2018. During the three months ended September 30, 2019, we received $0.6 million in lease bonus payments to extend the term of three leases and $0.1 million for three new leases. During the three months ended September 30, 2018, we received $4.2 million in lease bonus payments to extend the term of 13 leases.

Production and Ad Valorem Taxes

Production taxes per unit of production for the three months ended September 30, 2019 and 2018 were $1.77 and $2.14, respectively. The decrease in production taxes per unit of production during the three months ended September 30, 2019 was primarily due to a 16% increase in production volumes, as compared to a 2% decrease in revenue year over year. 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, while ad valorem taxes are generally based on the valuation of our oil and natural gas interests. Ad valorem taxes per unit of production for the three months ended September 30, 2019 and 2018 were $0.65 and $0.83, respectively. The decrease in ad valorem taxes per unit of production during the three months ended September 30, 2019 was primarily due to a higher percentage increase in production volumes as compared to the increase in the valuation of oil and natural gas interests year over year.

	Three Months Ended September 30,			
	2019		2018	
	Amount	Per BOE	Amount	Per BOE
Production taxes	$ 3,455	$ 1.77	$ 3,615	$ 2.14
Ad valorem taxes	1,276	0.65	1,412	0.83
Total production and ad valorem taxes	$ 4,731	$ 2.42	$ 5,027	$ 2.97

Depletion

Depletion expense increased by $2.2 million to $18.7 million for the three months ended September 30, 2019 from $16.5 million for the three months ended September 30, 2018. The increase resulted primarily from higher production levels and an increase in net book value on new reserves added.

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 three months ended September 30, 2019 and 2018, we incurred general and administrative expenses of $1.8 million and $1.3 million, respectively. The increase of $0.5 million during the three months ended September 30, 2019 was primarily due to an increase in expenses allocated from the General Partner under the Partnership Agreement.

Net Interest Expense

The net interest expense for the three months ended September 30, 2019 and 2018 reflects the interest incurred under our credit agreement. Net interest expense for the three months ended September 30, 2019 and 2018 was $3.8 million and $3.7 million, respectively.

Provision for (Benefit from) Income Taxes

We recorded an income tax benefit of $7.5 million and an income tax expense $0.8 million for the three months ended September 30, 2019 and 2018, respectively. The change in our income tax provision was primarily due to revision during the three months ended September 30, 2019 of estimated deferred taxes recognized as a result of our change in federal income tax status. Total income tax benefit for the three months ended September 30, 2019 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the period primarily due to the revision of estimated deferred taxes recognized as a result of the Partnership's change in tax status and net income attributable to the non-controlling interest.

Comparison of the Nine Months Ended September 30, 2019 and 2018

Royalty Income

Our royalty income for the nine months ended September 30, 2019 and 2018 was $202.0 million and $209.9 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

The decrease in average prices received during the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018 was partially offset by a 23% increase in combined volumes sold by our operators as compared to the nine months ended September 30, 2018.

	Change in prices	Production volumes(1)	Total net dollar effect of change
			(in thousands)
Effect of changes in price:			
Oil	$ (8.50)	3,607	$ (30,652)
Natural gas	$ (1.19)	5,222	(6,219)
Natural gas liquids	$ (10.75)	976	(10,496)
Total income due to change in price			$ (47,367)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change
			(in thousands)
Effect of changes in production volumes:			
Oil	482	$ 59.14	$ 28,529
Natural gas	1,155	$ 2.14	2,470
Natural gas liquids	331	$ 25.42	8,416
Total income due to change in production volumes			39,415
Total change in income			$ (7,952)

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

Lease Bonus Income

Lease bonus income decreased by $1.5 million for the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018. During the nine months ended September 30, 2019, we received $0.7 million in lease bonus payments to extend the term of nine leases and $2.9 million for 13 new leases. During the nine months ended September 30, 2018, we received $5.1 million in lease bonus payments to extend the term of 16 leases.

Production and Ad Valorem Taxes

Production taxes per unit of production for the nine months ended September 30, 2019 and 2018 were $1.78 and $2.28, respectively. The decrease in production taxes per unit of production during the nine months ended September 30, 2019 was primarily due to a 23% increase in production volumes, as compared to a 3% decrease in revenue year over year. 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, while ad valorem taxes are generally based on the valuation of our oil and natural gas interests. Ad valorem taxes per unit of production for the nine months ended September 30, 2019 and 2018 were $0.57 and $0.90, respectively. The decrease in ad valorem taxes per production unit during the nine months ended September 30, 2019 was primarily due to a higher percentage increase in production volumes as compared to the increase in the valuation of oil and natural gas interests year over year.

	Nine Months Ended September 30,			
	2019		2018	
	Amount	Per BOE	Amount	Per BOE
Production taxes	$ 9,671	$ 1.78	$ 10,160	$ 2.28
Ad valorem taxes	3,141	0.57	3,973	0.90
Total production and ad valorem taxes	$ 12,812	$ 2.35	$ 14,133	$ 3.18

Depletion

Depletion expense increased by $10.1 million to $51.4 million for the nine months ended September 30, 2019 from $41.3 million for the nine months ended September 30, 2018. The increase resulted primarily from higher production levels and an increase in net book value on new reserves added.

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, 2019 and 2018, we incurred general and administrative expenses of $5.2 million and $6.2 million, respectively. The decrease of $1.0 million during the nine months ended September 30, 2019 was primarily due to higher legal expenses in 2018 related to the change in tax structure that took place in March 2018 coupled with a slight decrease in unit-based compensation expense. These decreases were partially offset by an increase in expenses allocated from the General Partner under the Partnership Agreement.

Net Interest Expense

The net interest expense for the nine months ended September 30, 2019 and 2018 reflects the interest incurred under our credit agreement. Net interest expense for the nine months ended September 30, 2019 and 2018 was $11.1 million and $9.1 million, respectively. The increase of $2.0 million was due to increased borrowings and a higher interest rate during the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018.

Benefit from Income Taxes

We recorded an income tax benefit of $41.9 million and $71.1 million for the nine months ended September 30, 2019 and 2018, respectively. The change in our income tax provision was primarily due to a deferred benefit recognized during the nine months ended September 30, 2018 as a result of our change in federal income tax status. Prior to the second quarter of 2018, we had no provision for or benefit from income taxes. Total income tax benefit for the nine months ended September 30, 2019 differed from amounts computed by applying the federal statutory tax rate to pre-tax income for the period primarily due to the revision of estimated deferred taxes recognized as a result of the Partnership's change in tax status and net income attributable to the non-controlling interest.

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, loss (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,	
	2019	2018	2019	2018
	(In thousands)			
Net income	$ 51,097	$ 50,812	$ 172,682	$ 222,172
Interest expense, net	3,827	3,711	11,089	9,061
Non-cash unit-based compensation expense	449	426	1,326	2,166
Depletion	18,697	16,532	51,408	41,317
Loss (gain) on revaluation of investment	(336)	199	(3,978)	(5,165)
Provision for (benefit from) income taxes	(7,480)	764	(41,908)	(71,114)
Consolidated Adjusted EBITDA	66,254	72,444	190,619	198,437
EBITDA attributable to non-controlling interest	(35,525)	(42,256)	(102,216)	(85,898)
Adjusted EBITDA attributable to Viper Energy Partners LP	$ 30,729	$ 30,188	$ 88,403	$ 112,539

Non-GAAP Financial Measures

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

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

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

	Three Months Ended September 30, 2019				Three Months Ended September 30, 2018			
(in thousands)	Oil	Natural gas	Natural gas liquids	Total	Oil	Natural gas	Natural gas liquids	Total
Net oil, natural gas and natural gas liquids sales (GAAP)	$ 64,829	$ 2,181	$ 4,070	$ 71,080	$ 63,355	$ 3,603	$ 6,539	$ 73,497
Plus: Gathering and transportation expenses	396	611	539	1,546	236	321	332	889
Gross oil natural gas and natural gas liquids sales (non-GAAP)	$ 65,225	$ 2,792	$ 4,609	$ 72,626	$ 63,591	$ 3,924	$ 6,871	$ 74,386
Sales volumes (MBbl/MMcf/MBoe)	1,258	1,710	413	1,956	1,167	1,624	254	1,691
Gross sales price (non-GAAP)	$ 51.85	$ 1.63	$ 11.15	$ 37.12	$ 54.51	$ 2.42	$ 27.05	$ 43.98

	Nine Months Ended September 30, 2019				Nine Months Ended September 30, 2018			
(in thousands)	Oil	Natural gas	Natural gas liquids	Total	Oil	Natural gas	Natural gas liquids	Total
Net oil, natural gas and natural gas liquids sales (GAAP)	$ 182,679	$ 4,946	$ 14,325	$ 201,950	$ 184,802	$ 8,695	$ 16,405	$ 209,902
Plus: Gathering and transportation expenses	995	1,180	1,036	3,211	361	458	478	1,297
Gross oil natural gas and natural gas liquids (non-GAAP)	$ 183,674	$ 6,126	$ 15,361	$ 205,161	$ 185,163	$ 9,153	$ 16,883	$ 211,199
Sales volumes (MBbl/MMcf/MBoe)	3,607	5,222	976	5,454	3,125	4,067	645	4,448
Gross sales price (non-GAAP)	$ 50.92	$ 1.17	$ 15.73	$ 37.62	$ 59.26	$ 2.25	$ 26.16	$ 47.49

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, issuance of common units to the sellers 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 25, 2019, the board of directors of our general partner approved a cash distribution for the third quarter of 2019 of $0.46 per common unit, payable on November 15, 2019, to eligible unitholders of record at the close of business on November 8, 2019. Diamondback received Class B units and units in the Operating Company upon the closing of the Drop-Down Acquisition on October 1, 2019 and we will issue common units to Santa Elena at the closing of the Pending Santa Elena Acquisition. Each of Diamondback and Santa Elena has waived its right to receive distributions for the third quarter of 2019 in respect of the applicable equity interests issued in these transactions and the cash distribution for the third quarter of 2019 has been calculated on this basis.

2019 Equity Offering

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

Cash Flows

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

	Nine Months Ended September 30,	
	2019	**2018**
	(in thousands)	
Cash Flow Data:		
Net cash provided by operating activities	$ 164,228	$ 176,414
Net cash used in investing activities	(327,196)	(509,964)
Net cash provided by financing activities	160,244	326,182
Net decrease in cash	$ (2,724)	$ (7,368)

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 $327.2 million and $510.0 million during the nine months ended September 30, 2019 and 2018, respectively, and related to acquisitions of oil and natural gas interests and land.

Financing Activities

Net cash provided by financing activities was $160.2 million during the nine months ended September 30, 2019, primarily related to net proceeds from our public offering of common units of $340.6 million, offset by repayments from net borrowing activity under our credit facility of $1.5 million and distributions of $178.2 million to our unitholders during the period. 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 that period.

The Operating Company's Revolving Credit Facility

On July 20, 2018, we, as guarantor, entered into an amended and restated credit agreement with the Operating Company, as borrower, Wells Fargo, as administrative agent, and the other lenders. The credit agreement, as amended to the date hereof, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on our oil and natural gas reserves and other factors of $725.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. Upon closing of the Drop-Down Acquisition on October 1, 2019, the borrowing base under the Operating Company's revolving credit facility was increased by $125.0 million to $725.0 million from $600.0 million. In connection with the commencement of the Notes Offering described in this report, we entered into a third amendment to the Operating Company's revolving credit facility with Wells Fargo, as administrative agent, and certain required lenders party thereto, which provides for the waiver of the automatic reduction of the borrowing base that would otherwise occur upon the consummation of the Notes Offering. In addition, the third amendment increased the maximum amount of unsecured senior or senior subordinated notes that may be issued by the Operating Company or us from $400.0 million to $1.0 billion. The amendment was approved by the requisite percentage of lenders under the revolving credit facility and became effective on October 8, 2019. If the amendment had not been approved, the borrowing base under the revolving credit facility would have decreased by $125.0 million upon consummation of the Notes Offering.

As of September 30, 2019, when the borrowing base was set at $600.0 million, the Operating Company had $409.5 million of outstanding borrowings and $190.5 million available for future borrowings under the Operating Company's revolving credit facility. The Partnership funded the cash portion of the purchase price for the Drop-Down Acquisition through a combination of cash on hand and borrowings under the Operating Company's revolving credit facility. The Operating Company used the proceeds from the Notes Offering to pay down borrowings under its revolving credit facility. Following these transactions, as of October 16, 2019, the closing date of the Notes Offering, there was $94.5 million in outstanding borrowings under the Operating Company's revolving credit facility, the borrowing base under the Operating Company's revolving credit facility was $725.0 million, and the Operating Company had $630.5 million of available borrowing capacity under the Operating Company's revolving credit facility. Additionally, in connection with our fall redetermination expected to occur in November 2019, the lead bank under the Operating Company's revolving credit facility has recommended a borrowing base increase to $775.0 million from the current borrowing base of $725.0 million. The anticipated increase in the borrowing base is subject to approval by the requisite lenders under the Operating Company's revolving credit facility.

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

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $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, 2019, 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.

Notes Offering

On October 16, 2019, we completed an offering of our 5.375% Senior Notes due 2027 in the aggregate principal amount of $500.0 million. We received net proceeds of approximately $492.0 million from the Notes Offering. We loaned the gross proceeds of the Notes Offering to the Operating Company. The Operating Company used the proceeds from the Notes Offering to repay then outstanding borrowings under its revolving credit facility.

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

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

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

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

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

Intercompany Promissory Note

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

Contractual Obligations

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, 2018.

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, 2018.

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 driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production, as well as futures contract prices for oil and natural gas, since our operators generally hedge a majority of their 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 and producers. For the nine months ended September 30, 2019, three purchasers each accounted for more than 10% of our royalty income: Trafigura Trading LLC (29%), Concho Resources, Inc. (17%) and Shell Trading (US) Company (13%). 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%). 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, 2019, we had $409.5 million in outstanding borrowings. Our weighted average interest rate on borrowings under our revolving credit facility was 5.98%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $4.1 million based on the $409.5 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, 2019, an evaluation was performed under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon the evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner have concluded that as of September 30, 2019, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2019 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 discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10–K for the year ended December 31, 2018 and in subsequent filings we make with the SEC. Except as disclosed in this report with respect to the recent acquisitions, the Pending Santa Elena Acquisition and the Notes Offering, there have been no material changes in our risk factors from those described in our Annual Report on Form 10–K for the year ended December 31, 2018.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

As previously reported, on October 1, 2019, we issued approximately 18.3 million of our newly issued Class B units and the Operating Company issued approximately 18.3 million of its newly issued units, in each case to Diamondback, as part of the consideration for the Drop-Down Acquisition described elsewhere in this report, which consideration also included $190.2 million in cash after giving effect to closing adjustments for net title benefits. These units were issued in reliance upon the exemption from the registration requirements of the Securities Act, provided by Section 4(a)(2) of the Securities Act as sales by an issuer not involving any public offering.

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).
4.2	Indenture, dated as of October 16, 2019, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor and Wells Fargo Bank, National Association, as trustee (including the form of Viper Energy Partners LP's 5.375% Senior Notes due 2027) (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
10.1	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on September 30, 2019).
10.2	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 10, 2019).
10.3	Subordinated Promissory Note, dated as of October 16, 2019, by Viper Energy Partners LLC in favor of Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
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	The following financial information from the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statement of Changes in Unitholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Condensed Notes to Consolidated Financial Statements.
104.0	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* 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.

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, 2019	By:	/s/ Travis D. Stice
			Travis D. Stice
			Chief Executive Officer
Date:	October 30, 2019	By:	/s/ Teresa L. Dick
			Teresa L. Dick
			Chief Financial Officer

EXHIBIT 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Viper Energy Partners LP (the “registrant”).
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 30, 2019

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer
Viper Energy Partners GP LLC
(as general partner of Viper Energy Partners LP)

EXHIBIT 31.2

CERTIFICATION

I, Teresa L. Dick, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Viper Energy Partners LP (the “registrant”).
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 30, 2019

/s/ Teresa L. Dick

Teresa L. Dick
Chief Financial Officer
Viper Energy Partners GP LLC
(as general partner of Viper Energy Partners LP)

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

In connection with the Quarterly Report on Form 10-Q of Viper Energy Partners LP (the “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, Travis D. Stice, Chief Executive Officer of Viper Energy Partners GP LLC, the general partner of Viper Energy Partners LP, and Teresa L. Dick, Chief Financial Officer of Viper Energy Partners GP LLC, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to their knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date:	October 30, 2019	/s/ Travis D. Stice
		Travis D. Stice Chief Executive Officer Viper Energy Partners GP LLC (as general partner of Viper Energy Partners LP)
Date:	October 30, 2019	/s/ Teresa L. Dick
		Teresa L. Dick Chief Financial Officer Viper Energy Partners GP LLC (as general partner of Viper Energy Partners LP)