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

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2014
OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas	79701
(Address of Principal Executive Offices)	(Zip Code)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

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

Large Accelerated Filer	ý	Accelerated Filer	¨

Non-Accelerated Filer o Smaller Reporting Company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
As of October 29, 2014, 56,752,819 shares of the registrant’s common stock were outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used throughout this report:

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Bbls per day.

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

BOE/d. BOE per day.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.
Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
PDP. Proved developed producing.
Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD. Proved undeveloped.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
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.
Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.
Structural play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this quarterly report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may “continue,” “predict,” “potential,” “project,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this quarterly report on Form 10–Q and detailed under Part II, Item 1A. Risk Factors in this report and our Annual Report on Form 10–K for the year ended December 31, 2013 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:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

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

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

	September 30, 2014	December 31, 2013
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$40,644	$15,555
Accounts receivable:		
Joint interest and other	39,626	14,437
Oil and natural gas sales	46,687	23,533
Related party	3,915	1,303
Inventories	3,105	5,631
Deferred income taxes	—	112
Derivative instruments	6,061	213
Prepaid expenses and other	3,223	1,184
Total current assets	143,261	61,968
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($867,479 and $369,561 excluded from amortization at September 30, 2014 and December 31, 2013, respectively)	2,900,293	1,648,360
Pipeline and gas gathering assets	7,102	6,142
Other property and equipment	47,286	4,071
Accumulated depletion, depreciation, amortization and impairment	(328,522)	(212,236)
	2,626,159	1,446,337
Derivative instruments	—	218
Other assets	51,135	13,091
Total assets	$2,820,555	$1,521,614
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable-trade	$8,009	$2,679
Accounts payable-related party	—	17
Accrued capital expenditures	118,514	74,649
Other accrued liabilities	50,768	34,750
Revenues and royalties payable	17,951	9,225
Deferred income taxes	1,044	—
Total current liabilities	196,286	121,320
Long-term debt	590,000	460,000
Asset retirement obligations	8,115	2,989
Deferred income taxes	140,308	91,764
Total liabilities	934,709	676,073
Contingencies (Note 13)		
Stockholders’ equity:		
	567	471

Common stock, $0.01 par value, 100,000,000 shares authorized, 56,680,359 issued and outstanding at September 30, 2014; 47,106,216 issued and outstanding at December 31, 2013		
Additional paid-in capital	1,553,367	842,557
Retained earnings	97,594	2,513
Total Diamondback Energy, Inc. stockholders' equity	1,651,528	845,541
Noncontrolling interest	234,318	—
Total equity	1,885,846	845,541
Total liabilities and equity	$2,820,555	$1,521,614

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$126,406	$53,086	$331,446	$119,373
Natural gas sales	2,338	859	6,006	2,586
Natural gas sales - related party	2,374	704	6,370	1,796
Natural gas liquid sales	3,619	1,970	9,507	5,441
Natural gas liquid sales - related party	4,390	1,172	10,806	2,898
Total revenues	139,127	57,791	364,135	132,094
Costs and expenses:				
Lease operating expenses	13,766	4,718	31,998	14,527
Lease operating expenses - related party	39	246	218	840
Production and ad valorem taxes	8,634	3,420	22,318	7,970
Production and ad valorem taxes - related party	320	133	1,032	325
Gathering and transportation	110	69	426	175
Gathering and transportation - related party	750	192	1,719	466
Depreciation, depletion and amortization	45,370	17,423	116,364	42,976
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $2,069 and $490 for the three months ended September 30, 2014 and 2013, respectively, and $5,387 and $1,426 for the nine months ended September 30, 2014 and 2013, respectively)	6,016	1,810	13,891	6,350
General and administrative expenses - related party	479	311	1,095	863
Asset retirement obligation accretion expense	127	46	303	134
Total costs and expenses	75,611	28,368	189,364	74,626
Income from operations	63,516	29,423	174,771	57,468
Other income (expense)				
Interest income	—	1	—	1
Interest expense	(9,846)	(1,089)	(24,090)	(2,109)
Other income	17	—	17	—
Other income - related party	31	270	91	1,047
Other expense	(8)	—	(1,416)	—
Gain (loss) on derivative instruments, net	14,909	(4,910)	(577)	(1,881)
Total other income (expense), net	5,103	(5,728)	(25,975)	(2,942)
Income before income taxes	68,619	23,695	148,796	54,526
Provision for income taxes				
Current	3,982	—	3,982	—
Deferred	19,996	9,099	48,760	20,063
Net income	44,641	14,596	96,054	34,463
Less: Net income attributable to noncontrolling interest	902	—	973	—
Net income attributable to Diamondback Energy, Inc.	$43,739	$14,596	$95,081	$34,463

Earnings per common share				
Basic	$0.79	$0.33	$1.85	$0.85
Diluted	$0.79	$0.33	$1.83	$0.85
Weighted average common shares outstanding				
Basic	55,152	44,385	51,489	40,309
Diluted	55,442	44,698	51,888	40,524

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity
(Unaudited)

	Common Stock		Additional Paid-in	Retained	Non-controlling	
	Shares	Amount	Capital	Earnings	Interest	Total
	(In thousands)					
Balance December 31, 2013	47,106	$471	$842,557	$2,513	$—	$845,541
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	232,334	232,334
Unit-based compensation	—	—	—	—	1,011	1,011
Stock based compensation	—	—	9,134	—	—	9,134
Tax benefits related to stock-based compensation	—	—	3,173	—	—	3,173
Common shares issued in public offering, net of offering costs	9,200	92	693,289	—	—	693,381
Exercise of stock options and vesting of restricted stock units	380	4	5,214	—	—	5,218
Net income	—	—	—	95,081	973	96,054
Balance September 30, 2014	56,686	$567	$1,553,367	$97,594	$234,318	$1,885,846

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$96,054	$34,463
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	48,760	20,063
Excess tax benefit from stock-based compensation	749	—
Asset retirement obligation accretion expense	303	134
Depreciation, depletion, and amortization	116,364	42,976
Amortization of debt issuance costs	1,505	526
Change in fair value of derivative instruments	(5,630)	(3,733)
Stock based compensation expense	5,387	1,426
(Gain) loss on sale of assets, net	1,405	(31)
Changes in operating assets and liabilities:		
Accounts receivable	(33,985)	(13,262)
Accounts receivable-related party	(2,612)	(350)
Inventories	915	309
Prepaid expenses and other	(5,681)	(1,376)
Accounts payable and accrued liabilities	7,812	7,324
Accounts payable and accrued liabilities-related party	(17)	(82)
Accrued interest	11,940	—
Revenues and royalties payable	8,726	3,260
Net cash provided by operating activities	251,995	91,647
Cash flows from investing activities:		
Additions to oil and natural gas properties	(309,009)	(188,201)
Additions to oil and natural gas properties-related party	(3,410)	(11,594)
Acquisition of Gulfport properties	—	(18,550)
Acquisition of mineral interests	(57,688)	(440,000)
Acquisition of leasehold interests	(840,482)	(166,635)
Pipeline and gas gathering assets	(1,437)	—
Purchase of other property and equipment	(43,215)	(4,965)
Proceeds from sale of property and equipment	11	62
Cost method investment	(33,851)	—
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	(1,289,081)	(830,172)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	425,900	49,000
Repayment on credit facility	(295,900)	(49,000)
Proceeds from senior notes	—	450,000
Debt issuance costs	(2,358)	(9,524)
Public offering costs	(2,203)	(505)
Proceeds from public offerings	928,432	322,680
Exercise of stock options	5,131	2,616

Excess tax benefits of stock-based compensation	3,173	—
Net cash provided by financing activities	1,062,175	765,267
Net increase in cash and cash equivalents	25,089	26,742
Cash and cash equivalents at beginning of period	15,555	26,358
Cash and cash equivalents at end of period	$40,644	$53,100

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows - Continued
(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$12,729	$383
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$567	$162
Asset retirement obligation revisions in estimated liability	$588	$—
Asset retirement obligation acquired	$3,678	$471
Change in accrued capital expenditures	$43,865	$25,793
Capitalized stock based compensation	$4,758	$679

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
(Unaudited)

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. ("Diamondback" or the "Company"), together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011.

On June 17, 2014, Diamondback entered into a contribution agreement (the "Contribution Agreement") with Viper Energy Partners LP (the "Partnership"), Viper Energy Partners GP LLC (the "General Partner") and Viper Energy Partners LLC to transfer Diamondback's ownership interest in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. Diamondback also owns and controls the General Partner, which holds a non-economic general partner interest in the Partnership. On June 23, 2014, the Partnership completed its initial public offering (the "Viper Offering") of 5,750,000 common units, and the Company's common units represented an approximate 92% limited partner interest in the Partnership. On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. At the completion of this offering, the Company owned approximately 88% of the common units of the Partnership. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership.

The wholly owned subsidiaries of Diamondback, as of September 30, 2014, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, and White Fang Energy LLC, a Delaware limited liability company. The consolidated subsidiaries include the wholly owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership and Viper Energy Partners LLC, a Delaware limited liability company.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

The Partnership is consolidated in the financial statements of the Company. As of September 30, 2014, the Company owned approximately 88% of the common units of the Partnership and the Company's wholly owned subsidiary, Viper Energy Partners GP LLC, is the General Partner of the Partnership.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (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 accounting principles generally accepted in the United States have been omitted pursuant to such rules and regulations, although the Company 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 Company's most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2013, which contains a summary of the Company's significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company's consolidated 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 consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company's disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

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The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Recent Accounting Pronouncements

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

3. ACQUISITIONS

2014 Activity

On September 9, 2014, the Company completed the acquisition of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 17,617 gross (12,967 net) acres with an approximate 74% working interest (approximately 75% net revenue interest). The acquisition was accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. This acquisition was funded in part by the net proceeds of the July 2014 equity offering discussed in Note 8 below.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition date. The aggregate consideration transferred was $523,260,000 in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

	(in thousands)
Joint interest receivables	$42
Proved oil and natural gas properties	128,589
Unevaluated oil and natural gas properties	400,527
Total assets acquired	529,158
Accrued production and ad valorem taxes	358
Revenues payable	3,174
Asset retirement obligations	2,366
Total liabilities assumed	5,898
Total fair value of net assets	$523,260

The Company has included in its consolidated statements of operations revenues of $2,804,000 and direct operating expenses of $1,424,000 for the period from September 9, 2014 to September 30, 2014 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

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On August 25, 2014, the Company completed an acquisition of surface rights in the Permian Basin from an unrelated third party seller. The Company acquired surface rights to approximately 4,200 acres for approximately $41.9 million. On February 27 and 28, 2014, the Company completed acquisitions of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded in part by the net proceeds of the February 2014 equity offering discussed in Note 8 below. The following represents the estimated fair values of the assets and liabilities assumed on the acquisition dates. The aggregate consideration transferred was $292,159,000 in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

	(in thousands)
Proved oil and natural gas properties	$170,174
Unevaluated oil and natural gas properties	123,243
Total assets acquired	293,417
Asset retirement obligations	1,258
Total liabilities assumed	1,258
Total fair value of net assets	$292,159

The Company has included in its consolidated statements of operations revenues of $30,965,000 and direct operating expenses of $4,738,000 for the period from February 28, 2014 to September 30, 2014 due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

During the nine months ended September 30, 2014, the Partnership acquired (i) mineral interests underlying an aggregate of approximately 10,565 gross (3,461) net acres in the Midland and Delaware basins for approximately $57.7 million and (ii) a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests for approximately $33.9 million. The equity interest is so minor that we have no influence over partnership operating and financial polices and is accounted for under the cost method.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the three months and nine months ended September 30, 2014 and 2013 have been prepared to give effect to the February 27 and 28, 2014 acquisitions and the September 9, 2014 acquisition as if they had occurred on January 1, 2013. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2013. The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Pro Forma) (in thousands, except per share amounts)			
Revenues	$139,127	$87,809	$409,520	$214,671
Income from operations	63,516	44,300	186,483	90,967
Net income	43,739	23,760	102,583	55,576
Basic earnings per common share	$0.74	$0.46	$1.74	$1.09
Diluted earnings per common share	$0.74	$0.46	$1.73	$1.08

2013 Activity
In September 2013, the Company completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165.0 million, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013 when the Company acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres. The second of these acquisitions closed on September 26, 2013, when the Company acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 71% working interest (55% net revenue interest) in 9,390 gross (6,638 net) acres. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed in Note 8 below.

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. As part of the closing of the acquisition, the mineral interests were conveyed from the previous owners to Viper Energy Partners LLC and, subsequently, were contributed to the Partnership on June 17, 2014. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership. The mineral interests entitle the holder of such interests to receive a 21.4% royalty interest on all production on an acreage weighted basis from this acreage with no additional future capital or operating expense required. The $440.0 million purchase price was funded with the net proceeds of the Company’s offering of Senior Notes discussed in Note 7 below.

4. VIPER ENERGY PARTNERS LP
The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by Diamondback 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. Viper Energy Partners GP LLC, a fully consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of September 30, 2014, the Company owned approximately 88% of the common units of the Partnership.

Prior to the completion on June 23, 2014 of the Viper Offering, Diamondback owned all of the general and limited partner interests in the Partnership. The Viper Offering consisted of 5,750,000 common units representing approximately 8% of the limited partner interests in the Partnership at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. The Partnership received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the Viper Offering, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. In addition, in connection with the closing of the Viper Offering, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.6 million and the net proceeds from the Viper Offering. As of September 30, 2014, the Partnership had distributed $148.8 million to Diamondback. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and the Partnership received net proceeds of approximately

$95.1 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

The Company has also entered into the following agreements with the Partnership:

Partnership Agreement

In connection with the closing of the Viper Offering, the General Partner and Diamondback entered into the first amended and restated agreement of limited partnership (the “Partnership Agreement”), dated June 23, 2014. The Partnership Agreement requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership’s behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership’s business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on its 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.

Tax Sharing

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

Other Agreements

See Note 10—Related Party Transactions for details of the the advisory services agreement the Partnership and General Partner entered into with Wexford Capital LP (“Wexford”).

The Partnership has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, (“Wells Fargo”) as administrative agent sole book runner and lead arranger. See Note 7—Debt for a description of this credit facility.

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5. PROPERTY AND EQUIPMENT
Property and equipment includes the following:

	September 30, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$2,032,814	$1,278,799
Not subject to depletion-acquisition costs		
Incurred in 2014	594,465	—
Incurred in 2013	203,863	279,353
Incurred in 2012	68,387	87,252
Incurred in 2011	764	1,598
Incurred in 2010	—	1,358
Total not subject to depletion	867,479	369,561
Gross oil and natural gas properties	2,900,293	1,648,360
Less accumulated depreciation, depletion, amortization and impairment	(326,228)	(210,837)
Oil and natural gas properties, net	2,574,065	1,437,523
Pipeline and gas gathering assets, net	6,998	6,142
Other property and equipment, net	45,096	2,672
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$2,626,159	$1,446,337

The average depletion rate per barrel equivalent unit of production was $23.71 and $24.39 for the three months and nine months ended September 30, 2014, respectively, and $25.24 and $24.76 for the three months and nine months ended September 30, 2013, respectively. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $2,383,000 and $7,311,000 for the three months and nine months ended September 30, 2014, respectively, and $1,038,000 and $2,678,000 for the three months and nine months ended September 30, 2013, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years.

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6. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligation liability for the following periods:

	Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Asset retirement obligation, beginning of period	$3,029	$2,145
Additional liability incurred	567	162
Liabilities acquired	3,678	471
Liabilities settled	(10)	(14)
Accretion expense	303	134
Revisions in estimated liabilities	588	—
Asset retirement obligation, end of period	8,155	2,898
Less current portion	40	20
Asset retirement obligations - long-term	$8,115	$2,878

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

7. DEBT

Long-term debt consisted of the following as of the dates indicated:

	September 30, 2014	December 31, 2013
	(in thousands)	
Revolving credit facility	$140,000	$10,000
7.625 % Senior Notes due 2021	450,000	450,000
Total long-term debt	$590,000	$460,000

Senior Notes

On September 18, 2013, the Company completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the "Senior Notes"). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries and, upon such designation, Viper Energy LLC, which was a guarantor under the indenture governing of the Senior Notes, was released as a guarantor under the indenture. As of September 30, 2014, the Senior Notes are now fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin.

The Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee, as amended and supplemented (the "Indenture").

The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries. If the Company experiences certain kinds of changes of control or if it sells certain of its assets, holders of the Senior Notes may have the right to require the Company to repurchase their Senior Notes.

The Company will have the option to redeem the Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, the Company may redeem all or a part of the Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium at the redemption date. Furthermore, before October 1, 2016, the Company may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the Senior Notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the Senior Notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

In connection with the issuance of the Senior Notes, the Company and the subsidiary guarantors entered into a Registration Rights Agreement (the "Registration Rights Agreement") with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the Senior Notes for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on September 15, 2014 and the exchange offer completed on October 23, 2014.

Credit Facility-Wells Fargo Bank

The Company's secured second amended and restated credit agreement, dated November 1, 2013, with a syndication of banks, including Wells Fargo as administrative agent sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $600.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2014, the borrowing base was set at $350.0 million and the Company had outstanding borrowings of $140.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the 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 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018.

On June 9, 2014, Diamondback entered into a first amendment (the “First Amendment”) to the second amended and restated credit agreement, dated November 1, 2013 (together, the “Credit Agreement”). The First Amendment modified certain provisions of the credit agreement to, among other things, allow the Company to designate one or more of its subsidiaries as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries under the credit agreement. As of September 30, 2014, the loan is guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of the Company, Diamondback O&G LLC and the guarantors.

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750.0 million in the form of senior or senior subordinated 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, 2014, the Company had $450.0 million of senior unsecured notes outstanding.

As of September 30, 2014 and December 31, 2013, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the 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. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Partnership Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2014, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of September 30, 2014.

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

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

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

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

8. CAPITAL STOCK AND EARNINGS PER SHARE

As of September 30, 2014, Diamondback had completed the following equity offerings since the closing of its initial public offering on October 17, 2012:

On May 21, 2013, the Company completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $29.25 per share and the Company received net proceeds of approximately $144.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2013, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $40.25 per share and the Company received net proceeds of approximately $177.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In February 2014, the Company completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $62.67 per share and the Company received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On July 25, 2014, the Company completed an underwritten public offering of 5,750,000 shares of common stock, which included 750,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $87.00 per share and the Company received net proceeds of approximately $485.0 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Earnings Per Share

The Company's basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, for the diluted earnings per share computation, the per share earnings of the Partnership are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiary. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

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	Three Months Ended September 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$43,739	55,152	$0.79	$14,596	44,385	$0.33
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$(53)	290		—	313	
Diluted:						
Net income attributable to common stock	$43,686	55,442	$0.79	$14,596	44,698	$0.33

	Nine Months Ended September 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$95,081	51,489	$1.85	$34,463	40,309	$0.85
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$16	399		—	215	
Diluted:						
Net income attributable to common stock	$95,097	51,888	$1.83	$34,463	40,524	$0.85

9. STOCK BASED COMPENSATION

For the three months and nine months ended September 30, 2014, the Company incurred $4,112,000 and $10,145,000, respectively, of stock based compensation, of which the Company capitalized $2,043,000 and $4,758,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties. For the three months and nine months ended September 30, 2013, the Company incurred $749,000 and $2,105,000, respectively, of stock based compensation, of which the Company capitalized $259,000 and $679,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties.

On June 17, 2014, in connection with the Viper Offering, the Board of Directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan (“Viper 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 Viper LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. A total of 9,144,000 common units has been reserved for issuance pursuant to the Viper

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 Viper LTIP is administered by the Board of Directors of the General Partner or a committee thereof.

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Stock Options
The following table presents the Company's stock option activity under the 2012 Plan for the nine months ended September 30, 2014.

	Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	712,955	$17.96		
Granted	—	$—		
Exercised	(293,450)	$17.78		
Expired/Forfeited	—	$—		
Outstanding at September 30, 2014	419,505	$18.09	1.97	$23,783
Vested and Expected to vest at September 30, 2014	419,505	$18.09	1.97	$23,783
Exercisable at September 30, 2014	159,755	$17.50	1.47	$9,151

The aggregate intrinsic value of stock options that were exercised during the nine months ended September 30, 2014 was $16,778,000. As of September 30, 2014, the unrecognized compensation cost related to unvested stock options was $959,000. Such cost is expected to be recognized over a weighted-average period of 1.2 years.
Restricted Stock Units
The following table presents the Company's restricted stock units activity under the 2012 Plan during the nine months ended September 30, 2014.

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	132,499	$19.20
Granted	148,722	$66.93
Vested	(98,560)	$38.31
Forfeited	(1,200)	$41.66
Unvested at September 30, 2014	181,461	$47.80

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2014 was $7,248,000. As of September 30, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $6,703,000. Such cost is expected to be recognized over a weighted-average period of 1.6 years.
Performance Based Restricted Stock Units
To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period. In February 2014, eligible employees received initial performance restricted stock unit awards totaling 79,150 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2013 to December 31, 2015 and cliff vest at December 31, 2015. There were no performance restricted stock units issued or outstanding during the nine months ended September 30, 2013.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period. The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions.

	2014	
Grant-date fair value	$ 125.63	
Risk-free rate	0.30	%
Company volatility	39.60	%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the nine months ended September 30, 2014.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	—	$—
Granted	79,150	$125.63
Vested	—	$—
Forfeited	—	$—
Unvested at September 30, 2014 (1)	79,150	$125.63

(1) A maximum of 158,300 units could be awarded based upon the Company's final TSR ranking.

As of September 30, 2014, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $6,751,000. Such cost is expected to be recognized over a weighted-average period of 1.3 years.

Partnership Unit Options

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

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

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

The following table presents the unit option activity under the Viper LTIP for the nine months ended September 30, 2014.

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

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

10. RELATED PARTY TRANSACTIONS

Administrative Services

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms continued on a month-to-month basis. Effective August 31, 2014, this agreement was mutually terminated. For the three months and nine months ended September 30, 2014, the Company incurred total costs of $3,000 and $6,000, respectively. For the three months and nine months ended September 30, 2013, the Company incurred total costs of $70,000 and $179,000, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. As of September 30, 2014 and December 31, 2013, the Company owed the administrative services affiliate no amounts and $17,000, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provided this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement was two years. Thereafter, the agreement continued on a month-to-month basis subject to the right of either party to terminate the agreement upon thirty days prior written notice. Effective August 31, 2014, this agreement was mutually terminated. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the three months and nine months ended September 30, 2014, the affiliate reimbursed the Company $31,000 and $91,000, respectively, and for the three months and nine months ended September 30, 2013, the affiliate reimbursed the Company $270,000 and $1,047,000, respectively, for services under the shared services agreement. As of September 30, 2014 and

December 31, 2013, the affiliate owed the Company no amounts for either period.

Drilling Services

Bison Drilling and Field Services LLC ("Bison"), an entity controlled by Wexford, has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At September 30, 2014, the Company was not utilizing any Bison rigs. This master drilling agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. For the three months and nine months ended September 30, 2014, the Company incurred total costs for services performed by Bison of $907,000 and $3,402,000, respectively. For the three months and nine months ended September 30, 2013, the Company incurred total costs for services performed by Bison of $2,168,000 and $11,795,000, respectively. The Company owed Bison no amounts as of September 30, 2014 and December 31, 2013.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC ("Panther Drilling"), an entity controlled by Wexford, under which Panther Drilling provides directional drilling and other services. This master service agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling's directional drilling services, however the amount incurred for services performed by Panther Drilling during the nine months ended September 30, 2013 was not material. For the three months and nine months ended September 30, 2014, the Company incurred total costs for services performed by Panther Drilling of zero and $305,000, respectively. The Company owed Panther Drilling no amounts as of September 30, 2014 and December 31, 2013.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC ("Coronado Midstream"), formerly known as MidMar Gas LLC, an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, Coronado Midstream is obligated to pay the Company 87% of the net revenue received by Coronado Midstream for all components of the Company's dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at Coronado Midstream's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. The Company recognized revenues from Coronado Midstream of $6,764,000 and $17,176,000 for the three months and nine months ended September 30, 2014, respectively, and $1,877,000 and $4,694,000 for the three months and nine months ended September 30, 2013, respectively. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream of $1,070,000 and $2,751,000 for the three months and nine months ended September 30, 2014, respectively, and $325,000 and $791,000 for the three months and nine months ended September 30, 2013, respectively. As of September 30, 2014 and December 31, 2013, Coronado Midstream owed the Company $3,915,000 and $1,303,000, respectively, for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie Proppant LLC ("Muskie"), an entity affiliated with Wexford, processes and sells fracing grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company's requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days' notice. The Company purchased no sand from Muskie, and incurred no costs payable to Muskie, for the three months and nine months ended September 30, 2014, respectively. The Company incurred no costs and costs of $234,000 for sand purchased from Muskie for the three months and nine months ended September 30, 2013, respectively. The Company owed Muskie no amounts as of September 30, 2014 or December 31, 2013.

Midland Leases

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $97,000 and $288,000 for the three months and nine months ended September 30, 2014, respectively, and $49,000 and $131,000, for the three months and nine months ended September 30, 2013, respectively, under this lease. In the second and third quarters of 2013, the Company amended this agreement to increase the size of the leased premises. The monthly rent under the lease increased from $13,000 to $15,000 beginning on August 1, 2013 and increased further to $25,000 beginning on October 1, 2013. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011 to March 1, 2014. Effective March 1, 2014, the building was purchased by an entity controlled by an affiliate of Wexford. The remaining term of the lease as of March 1, 2014 is four years. The Company paid rent of $37,000 and $84,000 to the related party for the three months and nine months ended September 30, 2014. The monthly base rent is $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term. During the third quarter of 2014, the Company negotiated a sublease with Bison, in which Bison will lease the field office space for the same term as the initial lease and will pay the monthly rent of $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $74,000 and $199,000 for the three months and nine months ended September 30, 2014, respectively, and $67,000 and $178,000 for the three months and nine months ended September 30, 2013, respectively, under this lease. Effective April 1, 2013, the Company amended this lease to increase the size of the leased premises, at which time the monthly base rent increased to $19,000 for the remainder of the lease term. The Company was also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises. Effective September 23, 2014, this lease agreement was mutually terminated.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of $125,000 and $375,000 for the three months and nine months ended September 30, 2014, respectively, and $125,000 and $375,000 for the three months and nine months ended September 30, 2013, respectively, under the Advisory Services Agreement. As of September 30, 2014 and December 31, 2013, the Company owed Wexford no amounts for either period.

Advisory Services Agreement- Viper Energy Partners LP

In connection with the closing of the Viper Offering, the Partnership and General Partner entered into an advisory services agreement (the “Viper Advisory Services Agreement”) with Wexford, dated as of June 23, 2014, under which Wexford provides the Partnership and our General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement has a term of two years commencing on June 23, 2014, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Partnership or General Partner terminates such agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership and General Partner have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of our General Partner for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the Viper Advisory Services Agreement do not extend to the Partnership or General Partners day-to-day business or operations. The Partnership and General Partner have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Viper Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. For the three months and nine months ended September 30, 2014, the Partnership incurred costs of $143,000 and $143,000, respectively, under the agreement. As of September 30, 2014, the Partnership owed Wexford no amounts.

Secondary Offering Costs

On September 23, 2014, Gulfport Energy Corporation ("Gulfport") and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,500,000 shares of the Company's common stock. The Company incurred estimated costs of approximately $100,000 related to this secondary public offering.

On June 27, 2014, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,000,000 shares of the Company's common stock. The shares were sold to the public at $90.04 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of approximately $129,000 related to this secondary public offering.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of the Company's common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of approximately $185,000 related to this secondary public offering.

11. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company's fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing.

By using derivative instruments to hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company’s counterparties are participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company has entered into derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk.

As of September 30, 2014, the Company had open crude oil derivative positions with respect to future production as set forth in the table below. When aggregating multiple contracts, the weighted average contract price is disclosed.
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
October - December 2014	644,000	$98.64
January - April 2015	331,000	99.71

Balance sheet offsetting of derivative assets and liabilities
The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of September 30, 2014 and December 31, 2013.

	September 30, 2014		
	(in thousands)		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets	$6,061	$—	$6,061

	December 31, 2013		
	(in thousands)		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets	$998	$(567)	$431

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Current Assets: Derivative instruments	$6,061	$213
Noncurrent Assets: Derivative instruments	—	218
Total Assets	$6,061	$431

None of the Company’s derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Non-cash gain (loss) on open non-hedge derivative instruments	$16,440	$(1,695)	$5,630	$3,733
Loss on settlement of non-hedge derivative instruments	(1,531)	(3,215)	(6,207)	(5,614)
Gain (loss) on derivative instruments	$14,909	$(4,910)	$(577)	$(1,881)

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 Company’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 Company 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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company’s derivative instruments. The fair values of the Company’s fixed price crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2014 and December 31, 2013.

	Fair value measurements at September 30, 2014 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$—	$6,061	$—	$6,061

	Fair value measurements at December 31, 2013 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$—	$431	$—	$431

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements.

	September 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$140,000	$140,000	$10,000	$10,000
7.625% Senior Notes due 2021	450,000	486,000	450,000	460,406
Partnership revolving credit facility	—	—	—	—

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the September 30, 2014 quoted market price, a Level 1 classification in the fair value hierarchy. The fair value of the Partnership’s revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The Partnership had no outstanding borrowings as of September 30, 2014.

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

13. CONTINGENCIES

In September 2010, Windsor Permian LLC ("Windsor Permian") (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota, that was prospective for hydraulic fracturing grade sand. Prior to the purchase, the prior owners of the property had entered into a Mineral Development Agreement with the plaintiff and the Company purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by the plaintiff against the prior owners of the property, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, the plaintiff sought damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff's claims on the grounds that the damage claim was speculative and that plaintiff could not prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013. In March 2014, the judge entered an order granting the defendants' motions to exclude testimony and for summary judgment. All parties agreed not to pursue an appeal from the order and waived any entitlement to costs, which effectively concluded this matter.

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

14. SUBSEQUENT EVENTS

Subsequent to September 30, 2014, the Company entered into new commodity contracts. The contracts are fixed price oil swaps that will settle against the weighted average price per barrel of Argus Louisiana light sweet or NYMEX West Texas Intermediate during the calculation period. The following table presents the terms of the contracts:

	Volumes (Bbls)	Fixed Swap Price	Production Period		
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	183,000	$82.95	November 2014	-	December 2014
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	1,095,000	$90.99	January 2015	-	December 2015
Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap	1,825,000	$84.10	January 2015	-	December 2015
Crude Oil—ICE Brent Fixed Price Swap	640,000	$88.78	February 2015	-	January 2016
Crude Oil—ICE Brent Fixed Price Swap	91,000	$88.72	January 2016	-	February 2016

The Company’s lead lender under its revolving credit agreement recently approved an increase in the Company’s borrowing base to $750.0 million, however the Company has elected to limit the lenders’ aggregate commitment to $500.0 million.

15. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P, Diamondback O&G and White Fang Energy LLC (the “Guarantor Subsidiaries”) are guarantors under the Indenture relating to the Senior Notes. On June 23, 2014, in connection with the initial public offering of Viper Energy Partners LP, the Company designated the Partnership, its general partner, Viper Energy Partners GP, and the Partnership’s subsidiary Viper Energy Partners LLC (the “Non-Guarantor Subsidiaries”) as unrestricted subsidiaries under the Indenture and, upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information for the Company (“Parent”), the Guarantor Subsidiaries, the Non–Guarantor Subsidiaries and on a consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC’s Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$6,518	$20,622	$13,504	$—	$40,644
Accounts receivable	—	76,346	9,965	2	86,313
Accounts receivable - related party	—	3,915	—	—	3,915
Intercompany receivable	1,634,314	1,716,401	—	(3,350,715)	—
Inventories	—	3,105	—	—	3,105
Other current assets	336	8,381	567	—	9,284
Total current assets	1,641,168	1,828,770	24,036	(3,350,713)	143,261
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	2,389,296	510,997	—	2,900,293
Pipeline and gas gathering assets	—	7,102	—	—	7,102
Other property and equipment	—	47,286	—	—	47,286
Accumulated depletion, depreciation, amortization and impairment	—	(306,187)	(24,801)	2,466	(328,522)
	—	2,137,497	486,196	2,466	2,626,159
Investment in subsidiaries	693,594	—	—	(693,594)	—
Other assets	9,395	6,664	35,076	—	51,135
Total assets	$2,344,157	$3,972,931	$545,308	$(4,041,841)	$2,820,555
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$—	$8,009	$—	$—	$8,009
Intercompany payable	83,318	3,267,397	—	(3,350,715)	—
Other current liabilities	19,003	167,485	1,789	—	188,277
Total current liabilities	102,321	3,442,891	1,789	(3,350,715)	196,286
Long-term debt	450,000	140,000	—	—	590,000
Asset retirement obligations	—	8,115	—	—	8,115
Deferred income taxes	140,308	—	—	—	140,308
Total liabilities	692,629	3,591,006	1,789	(3,350,715)	934,709
Commitments and contingencies					
Stockholders’ equity:	1,651,528	381,925	543,519	(925,444)	1,651,528
Noncontrolling interest	—	—	—	234,318	234,318
Total equity	1,651,528	381,925	543,519	(691,126)	1,885,846
Total liabilities and equity	$2,344,157	$3,972,931	$545,308	$(4,041,841)	$2,820,555

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
December 31, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non– Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$526	$14,267	$762	$—	$15,555
Accounts receivable	—	28,544	—	9,426	37,970
Accounts receivable - related party	—	1,303	—	—	1,303
Royalty income receivable	—	—	9,426	(9,426)	—
Intercompany receivable	715,169	413,744	—	(1,128,913)	—
Intercompany note receivable	440,000	—	—	(440,000)	—
Inventories	—	5,631	—	—	5,631
Deferred income taxes	112	—	—	—	112
Other current assets	—	1,397	—	—	1,397
Total current assets	1,155,807	464,886	10,188	(1,568,913)	61,968
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,200,326	448,034	—	1,648,360
Pipeline and gas gathering assets	—	6,142	—	—	6,142
Other property and equipment	—	4,071	—	—	4,071
Accumulated depletion, depreciation, amortization and impairment	—	(207,037)	(5,199)	—	(212,236)
	—	1,003,502	442,835	—	1,446,337
Investment in subsidiaries	235,334	—	—	(235,334)	—
Other assets	10,207	3,102	—	—	13,309
Total assets	$1,401,348	$1,471,490	$453,023	$(1,804,247)	$1,521,614
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$2,679	$—	$—	$2,679
Accounts payable-related party	—	17	—	—	17
Intercompany payable	3,920	1,115,214	87	(1,119,221)	—
Intercompany accrued interest	—	—	9,692	(9,692)	—
Other current liabilities	10,123	108,245	256	—	118,624
Total current liabilities	14,043	1,226,155	10,035	(1,128,913)	121,320
Long-term debt	450,000	10,000	—	—	460,000
Intercompany note payable	—	—	440,000	(440,000)	—
Asset retirement obligations	—	2,989	—	—	2,989
Deferred income taxes	91,764	—	—	—	91,764
Total liabilities	555,807	1,239,144	450,035	(1,568,913)	676,073
Commitments and contingencies					
Stockholders' equity:	845,541	232,346	2,988	(235,334)	845,541
Total equity	845,541	232,346	2,988	(235,334)	845,541

Total liabilities and equity	$1,401,348	$1,471,490	$453,023	$(1,804,247)	$1,521,614

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$105,202	$—	$21,204	$126,406
Natural gas sales	—	3,824	—	888	4,712
Natural gas liquid sales	—	6,880	—	1,129	8,009
Royalty income	—	—	22,767	(22,767)	—
Total revenues	—	115,906	22,767	454	139,127
Costs and expenses:					
Lease operating expenses	—	13,805	—	—	13,805
Production and ad valorem taxes	—	7,475	1,460	19	8,954
Gathering and transportation	—	866	—	(6)	860
Depreciation, depletion and amortization	—	38,028	9,025	(1,683)	45,370
General and administrative expenses	4,063	1,039	2,143	(750)	6,495
Asset retirement obligation accretion expense	—	127	—	—	127
Total costs and expenses	4,063	61,340	12,628	(2,420)	75,611
Income (loss) from operations	(4,063)	54,566	10,139	2,874	63,516
Other income (expense)					
Interest expense	(8,821)	(708)	(317)	—	(9,846)
Other income	6	31	11	—	48
Other income - intercompany	—	750	—	(750)	—
Other expense	—	(8)	—	—	(8)
Other expense - intercompany	—	—	(750)	750	—
Gain (loss) on derivative instruments, net	—	14,909	—	—	14,909
Total other income (expense), net	(8,815)	14,974	(1,056)	—	5,103
Income (loss) before income taxes	(12,878)	69,540	9,083	2,874	68,619
Provision for income taxes	23,978	—	—	—	23,978
Net income (loss)	(36,856)	69,540	9,083	2,874	44,641
Less: Net income attributable to noncontrolling interest	—	—	—	902	902
Net income (loss) attributable to Diamondback Energy, Inc.	$(36,856)	$69,540	$9,083	$1,972	$43,739

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$51,745	$—	$1,341	$53,086
Natural gas sales	—	1,527	—	36	1,563
Natural gas liquid sales	—	3,080	—	62	3,142
Royalty income	—	—	1,439	(1,439)	—
Total revenues	—	56,352	1,439	—	57,791
Costs and expenses:					
Lease operating expenses	—	4,964	—	—	4,964
Production and ad valorem taxes	—	3,460	93	—	3,553
Gathering and transportation	—	260	1	—	261
Depreciation, depletion and amortization	—	16,944	445	34	17,423
General and administrative expenses	703	1,418	9	(9)	2,121
Asset retirement obligation accretion expense	—	46	—	—	46
Total costs and expenses	703	27,092	548	25	28,368
Income (loss) from operations	(703)	29,260	891	(25)	29,423
Other income (expense)					
Interest income	1	—	—	—	1
Interest expense	(68)	(399)	(622)	—	(1,089)
Other income	—	270	—	—	270
Gain on derivative instruments, net	—	(4,910)	—	—	(4,910)
Total other income (expense), net	(67)	(5,039)	(622)	—	(5,728)
Income (loss) before income taxes	(770)	24,221	269	(25)	23,695
Provision for income taxes	9,099	—	—	—	9,099
Net income (loss)	$(9,869)	$24,221	$269	$(25)	$14,596

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$280,024	$—	$51,422	$331,446
Natural gas sales	—	10,394	—	1,982	12,376
Natural gas liquid sales	—	17,394	—	2,919	20,313
Royalty income	—	—	55,869	(55,869)	—
Total revenues	—	307,812	55,869	454	364,135
Costs and expenses:					
Lease operating expenses	—	32,216	—	—	32,216
Production and ad valorem taxes	—	19,540	3,791	19	23,350
Gathering and transportation	—	2,151	—	(6)	2,145
Depreciation, depletion and amortization	—	98,445	19,602	(1,683)	116,364
General and administrative expenses	11,476	1,832	2,584	(906)	14,986
Asset retirement obligation accretion expense	—	303	—	—	303
Total costs and expenses	11,476	154,487	25,977	(2,576)	189,364
Income (loss) from operations	(11,476)	153,325	29,892	3,030	174,771
Other income (expense)					
Interest income - intercompany	10,755	—	—	(10,755)	—
Interest expense	(21,365)	(2,408)	(317)	—	(24,090)
Interest expense - intercompany	—	—	(10,755)	10,755	—
Other income	6	91	11	—	108
Other income - intercompany	—	906	—	(906)	—
Other expense	—	(1,416)	—	—	(1,416)
Other expense - intercompany	—	—	(906)	906	—
Gain (loss) on derivative instruments, net	—	(577)	—	—	(577)
Total other income (expense), net	(10,604)	(3,404)	(11,967)	—	(25,975)
Income (loss) before income taxes	(22,080)	149,921	17,925	3,030	148,796
Provision for income taxes	52,742	—	—	—	52,742
Net income (loss)	(74,822)	149,921	17,925	3,030	96,054
Less: Net income attributable to noncontrolling interest	—	—	—	973	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(74,822)	$149,921	$17,925	$2,057	$95,081

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$118,032	$—	$1,341	$119,373
Natural gas sales	—	4,346	—	36	4,382
Natural gas liquid sales	—	8,277	—	62	8,339
Royalty income	—	—	1,439	(1,439)	—
Total revenues	—	130,655	1,439	—	132,094
Costs and expenses:					
Lease operating expenses	—	15,367	—	—	15,367
Production and ad valorem taxes	—	8,202	93	—	8,295
Gathering and transportation	—	640	1	—	641
Depreciation, depletion and amortization	—	42,497	445	34	42,976
General and administrative expenses	2,399	4,814	9	(9)	7,213
Asset retirement obligation accretion expense	—	134	—	—	134
Total costs and expenses	2,399	71,654	548	25	74,626
Income (loss) from operations	(2,399)	59,001	891	(25)	57,468
Other income (expense)					
Interest income	1	—	—	—	1
Interest expense	(68)	(1,419)	(622)	—	(2,109)
Other income	—	1,047	—	—	1,047
Gain on derivative instruments, net	—	(1,881)	—	—	(1,881)
Total other income (expense), net	(67)	(2,253)	(622)	—	(2,942)
Income (loss) before income taxes	(2,466)	56,748	269	(25)	54,526
Provision for income taxes	20,063	—	—	—	20,063
Net income (loss)	$(22,529)	$56,748	$269	$(25)	$34,463

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$1,915	$220,447	$29,633	$—	$251,995
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(307,144)	(5,275)	—	(312,419)
Acquisition of leasehold interests	—	(840,482)	—	—	(840,482)
Acquisition of mineral interests	—	—	(57,688)	—	(57,688)
Purchase of other property and equipment	—	(43,215)	—	—	(43,215)
Cost method investment	—	—	(33,851)	—	(33,851)
Intercompany transfers	(631,100)	631,100	—	—	—
Other investing activities	—	(1,426)	—	—	(1,426)
Net cash used in investing activities	(631,100)	(561,167)	(96,814)	—	(1,289,081)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	347,900	78,000	—	425,900
Repayment on credit facility	—	(217,900)	(78,000)	—	(295,900)
Proceeds from public offerings	693,886	—	234,546	—	928,432
Distribution to parent	—	—	(148,760)	—	(148,760)
Distribution from subsidiary	148,760	—	—	—	148,760
Intercompany transfers	(217,900)	217,900	—	—	—
Other financing activities	10,431	(825)	(5,863)	—	3,743
Net cash provided by (used in) financing activities	635,177	347,075	79,923	—	1,062,175
Net increase in cash and cash equivalents	5,992	6,355	12,742	—	25,089
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$6,518	$20,622	$13,504	$—	$40,644

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$(182)	$91,243	$586	$—	$91,647
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(199,209)	(586)	—	(199,795)
Acquisition of leasehold interests	—	(185,185)	—	—	(185,185)
Acquisition of mineral interests	—	—	(440,000)	—	(440,000)
Purchase of other property and equipment	—	(4,965)	—	—	(4,965)
Intercompany transfers	(245,680)	245,680	—	—	—
Other investing activities	—	(227)	—	—	(227)
Net cash used in investing activities	(245,680)	(143,906)	(440,586)	—	(830,172)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	49,000	—	—	49,000
Repayment on credit facility	—	(49,000)	—	—	(49,000)
Proceeds from senior notes	10,000	—	440,000	—	450,000
Proceeds from public offerings	322,680	—	—	—	322,680
Distribution to parent	—	—	—	—	—
Intercompany transfers	(49,000)	49,000	—	—	—
Other financing activities	(7,267)	(146)	—	—	(7,413)
Net cash provided by (used in) financing activities	276,413	48,854	440,000	—	765,267
Net increase in cash and cash equivalents	30,551	(3,809)	—	—	26,742
Cash and cash equivalents at beginning of period	14	26,344	—	—	26,358
Cash and cash equivalents at end of period	$30,565	$22,535	$—	$—	$53,100

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

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10–Q as well as our audited combined consolidated financial statements and notes thereto included in our Annual Report on Form 10–K for the year ended December 31, 2013. 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 an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations which we refer to as the Wolfberry play. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. Our production was approximately 75% oil, 14% natural gas liquids and 11% natural gas for the three months ended September 30, 2014, and the three months ended September 30, 2013. Our production was approximately 76% oil, 14% natural gas liquids and 10% natural gas for the nine months ended September 30, 2014, and approximately 74% oil, 14% natural gas liquids and 12% natural gas for the nine months ended September 30, 2013. On September 30, 2014, our net acreage position in the Permian Basin was approximately 84,746 net acres. See Note 1 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional information regarding the organization and description of our business.

Recent Developments

Viper Energy Partners LP

Viper Energy Partners LP, or the Partnership, is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by us 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.

Prior to the completion on June 23, 2014 of the Partnership’s initial public offering, or the Viper Offering, we owned all of the general and limited partner interests in the Partnership. The Viper Offering consisted of 5,750,000 common units representing limited partner interests at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. The Partnership received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the Viper Offering, we contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. In addition, in connection with the closing of the Viper Offering, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.6 million and the net proceeds from the Viper Offering. As of September 30, 2014, the Partnership had distributed $148.8 million to Diamondback. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

Acquisitions

On February 27 and 28, 2014, we completed acquisitions of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Martin County, Texas, in the Permian Basin, for an aggregate purchase price of approximately $292.2 million, subject to certain adjustments. These transactions included 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). We funded these acquisitions with the net proceeds from an underwritten public offering of our common stock completed on February 26, 2014 and borrowings under our revolving credit facility. Upon completion of these acquisitions, we became the operator of this acquired acreage.

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On September 9, 2014, we completed the acquisition of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas in the Permian Basin, for an aggregate purchase price of approximately $523.3 million, subject to certain adjustments. This transaction included 17,617 gross (12,967 net) acres with an approximate 74% working interest (approximately 75% net revenue interest). We funded this acquisition with the net proceeds from an underwritten public offering of our common stock completed on July 25, 2014 and borrowings under our revolving credit facility. Upon completion of these acquisitions, we became the operator of this acquired acreage.

Common stock transactions

In February 2014, we completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $62.67 per share and we received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On July 25, 2014, we completed an underwritten public offering of 5,750,000 shares of common stock, which included 750,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $87.00 per share and we received net proceeds of approximately $485.0 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions. The net proceeds of this offering were used to partially fund the September 9, 2014 acquisition described above.

Unit transactions

On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and the Partnership received net proceeds of approximately $95.1 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

Operating Results Overview

During the three months ended September 30, 2014, our average daily production was approximately 20,636 BOE/d, consisting of 15,503 Bbls/d of oil, 13,058 Mcf/d of natural gas and 2,957 Bbls/d of natural gas liquids, an increase of 13,217 BOE/d, or 178%, from average daily production of 7,419 BOE/d for the three months ended September 30, 2013, consisting of 5,596 Bbls/d of oil, 4,850 Mcf/d of natural gas and 1,014 Bbls/d of natural gas liquids.

During the nine months ended September 30, 2014, our average daily production was approximately 17,367 BOE/d, consisting of 13,176 Bbls/d oil, 10,619 Mcf/d of natural gas and 2,422 Bbls/d of natural gas liquids, an increase of 11,092 BOE/d, or 177%, from average daily production of 6,275 BOE/d for the nine months ended September 30, 2013, consisting of 4,627 Bbls/d of oil, 4,417 Mcf/d of natural gas and 912 Bbls/d of natural gas liquids.

During the three months ended September 30, 2014, we drilled 27 gross (23 net) wells, and participated in one gross non-operated well, in the Permian Basin. During the nine months ended September 30, 2014, we drilled 82 gross (66 net) wells, and participated in an additional three gross (one net) non-operated wells, in the Permian Basin. Additionally, on properties acquired this year there were four gross (four net) wells drilled during the three months ended September 30, 2014 and ten gross (eight net) wells drilled during the nine months ended September 30, 2014 by the original operator between the effective date and closing date on the property acquired.

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Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the three months ended September 30, 2014 and 2013, our revenues were derived 91% and 92%, respectively, from oil sales, 6% and 5%, respectively, from natural gas liquids sales and 3% and 3%, respectively, from natural gas sales. For the nine months ended September 30, 2014 and 2013, our revenues were derived 91% and 90%, respectively, from oil sales, 6% and 7%, respectively, from natural gas liquids sales and 3% and 3%, respectively, from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2013, West Texas Intermediate posted prices ranged from $86.65 to $110.62 per Bbl and the Henry Hub spot market price of natural gas ranged from $3.08 to $4.52 per MMBtu. On December 31, 2013, the West Texas Intermediate posted price for crude oil was $98.17 per Bbl and the Henry Hub spot market price of natural gas was $4.31 per MMBtu.

The industry has recently observed a decline in oil prices from over $105.00 per Bbl in June 2014 to below $80.00 per Bbl currently, combined with increasing service costs. While we have not finalized our drilling plans for 2014, we intend to enter 2015 running our current five horizontal rigs. However, if service costs are not reduced or commodity prices don’t improve, we expect to respond by drilling fewer wells next year than we initially anticipated, although we intend to continue to run two horizontal rigs on our Spanish Trail acreage. Our decision to maintain or possibly reduce our current rig count, rather than increase it as previously contemplated, will be based on our goal of maximizing return on capital and minimizing debt until we can get a more attractive return on our assets.

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Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(unaudited)			
	(in thousands, except Bbl, Mcf and BOE amounts)			
Operating Results:				
Revenues				
Oil and natural gas revenues	$139,127	$57,791	$364,135	$132,094
Operating Expenses				
Lease operating expense	13,805	4,964	32,216	15,367
Production and ad valorem taxes	8,954	3,553	23,350	8,295
Gathering and transportation expense	860	261	2,145	641
Depreciation, depletion and amortization	45,370	17,423	116,364	42,976
General and administrative	6,495	2,121	14,986	7,213
Asset retirement obligation accretion expense	127	46	303	134
Total expenses	75,611	28,368	189,364	74,626
Income from operations	63,516	29,423	174,771	57,468
Net interest expense	(9,846)	(1,088)	(24,090)	(2,108)
Other income	48	270	108	1,047
Other expense	(8)	—	(1,416)	—
Gain (loss) on derivative instruments, net	14,909	(4,910)	(577)	(1,881)
Total other income (expense), net	5,103	(5,728)	(25,975)	(2,942)
Income before income taxes	68,619	23,695	148,796	54,526
Income tax provision	23,978	9,099	52,742	20,063
Net income	44,641	14,596	96,054	34,463
Less: Net income attributable to noncontrolling interest	902	—	973	—
Net income attributable to Diamondback Energy, Inc.	$43,739	$14,596	$95,081	$34,463
Production Data:				
Oil (Bbls)	1,426,271	514,853	3,596,983	1,263,097
Natural gas (Mcf)	1,201,296	446,195	2,899,097	1,205,763
Natural gas liquids (Bbls)	272,013	93,329	661,160	249,018
Combined volumes (BOE)	1,898,500	682,548	4,741,326	1,713,076
Daily combined volumes (BOE/d)	20,636	7,419	17,367	6,275
Average Prices[1]:				
Oil (per Bbl)	$88.63	$103.11	$92.15	$94.51
Natural gas (per Mcf)	3.92	3.50	4.27	3.63
Natural gas liquids (per Bbl)	29.44	33.67	30.72	33.49
Combined (per BOE)	73.28	84.67	76.80	77.11
Average Costs (per BOE)				
Lease operating expense	$7.27	$7.27	$6.79	$8.97
Gathering and transportation expense	0.45	0.38	0.45	0.37

Production and ad valorem taxes	4.72		5.21		4.92		4.84	
Production and ad valorem taxes as a % of sales	6.4	%	6.1	%	6.4	%	6.3	%
Depreciation, depletion, and amortization	23.90		25.53		24.54		25.09	
General and administrative[(2)]	3.42		3.11		3.16		4.21	
Interest expense	5.19		1.59		5.08		1.23	

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(1) After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $87.55 and $72.48, respectively, during the three months ended September 30, 2014, and $96.86 and $79.96, respectively, during the three months ended September 30, 2013. After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $90.42 and $75.49, respectively, during the nine months ended September 30, 2014, and $90.06 and $73.83, respectively, during the nine months ended September 30, 2013.

(2) General and administrative includes non-cash stock based compensation, net of capitalized amounts, of $2,069 and $490 for the three months ended September 30, 2014 and 2013, respectively. Excluding stock based compensation from the above metric results in general and administrative cost per BOE of $2.33 and $2.39 for the three months ended September 30, 2014 and 2013, respectively. General and administrative includes non-cash stock based compensation, net of capitalized amounts, of $5,387 and $1,426 for the nine months ended September 30, 2014 and 2013, respectively. Excluding stock based compensation from the above metric results in general and administrative cost per BOE of $2.03 and $3.38 for the nine months ended September 30, 2014 and 2013, respectively.

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Comparison of the Three Months Ended September 30, 2014 and 2013

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $81,336,000, or 141%, to $139,127,000 for the three months ended September 30, 2014 from $57,791,000 for the three months ended September 30, 2013. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 13,217 BOE/d to 20,636 BOE/d during the three months ended September 30, 2014 from 7,419 BOE/d during the three months ended September 30, 2013. The total increase in revenue of approximately $81,336,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 911,418 Bbls of oil, 178,684 Bbls of natural gas liquids and 755,101 Mcf of natural gas for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013. The net dollar effect of the decreases in prices of approximately $21,300,000 (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $102,636,000 (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(14.48)	1,426,271	$(20,655)
Natural gas liquids	$(4.23)	272,013	$(1,149)
Natural gas	$0.42	1,201,296	$504
Total revenues due to change in price			$(21,300)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	911,418	$103.11	$93,975
Natural gas liquids	178,684	$33.67	$6,016
Natural gas	755,101	$3.50	$2,645
Total revenues due to change in production volumes			$102,636
Total change in revenues			$81,336

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

Lease Operating Expense. Lease operating expense, or LOE, was $13,805,000 ($7.27 per BOE) for the three months ended September 30, 2014, an increase of $8,841,000, or 178%, from $4,964,000 ($7.27 per BOE) for the three months ended September 30, 2013. The increase is due to increased drilling activity and acquisitions, which resulted in additional producing wells, for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells. On a per BOE basis, LOE remained stable as new volumes came on line and expenses were held in line or were reduced.

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Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $8,954,000 for the three months ended September 30, 2014 from $3,553,000 for the three months ended September 30, 2013. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During the three months ended September 30, 2014, our production taxes per BOE decreased by $0.54 as compared to the three months ended September 30, 2013, primarily reflecting the impact of lower oil and natural gas prices on production taxes. Our ad valorem taxes have increased primarily as a result of increased valuations on our properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased $27,947,000, or 160%, from $17,423,000 for the three months ended September 30, 2013 to $45,370,000 for the three months ended September 30, 2014.

The following table provides components of our DD&A expense for the periods presented:

	Three Months Ended September 30,	
	2014	2013
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$45,010	$17,227
Depreciation of other property and equipment	360	196
DD&A	$45,370	$17,423
Oil and natural gas properties DD&A per BOE	$23.71	$25.24
Total DD&A per BOE	$23.90	$25.53

The increases in depletion of proved oil and natural gas properties of $27,783,000 for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013 resulted primarily from higher total production levels, increased net book value on new reserves added and an increase in capitalized interest to the full cost pool. On a per BOE basis, DD&A decreased primarily due to the increased net book value on new reserves and acquisitions.

General and Administrative Expense. General and administrative expense increased $4,374,000 from $2,121,000 for the three months ended September 30, 2013 to $6,495,000 for the three months ended September 30, 2014. The increase was due to increases in stock based compensation, salary, legal, common stock offering, professional service and advisory service expenses. These increases were partially offset by increases in general and administrative costs related to exploration and development activity capitalized to the full cost pool and increases in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the three months ended September 30, 2014 was $9,846,000 as compared to $1,088,000 for the three months ended September 30, 2013, an increase of $8,758,000. This increase was due primarily to the issuance of $450.0 million in aggregate principal amount of our 7.625% senior notes in September 2013.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2014 and 2013, we had a cash loss on settlement of derivative instruments of $1,531,000 and $3,215,000, respectively. For the three months ended September 30, 2014 and 2013, we had a non-cash gain on open derivative instruments of $16,440,000 and a non-cash loss on open derivative instruments of $1,695,000, respectively.

Income Tax Expense. We recorded income tax expense of $23,978,000 for the three months ended September 30, 2014 as compared to $9,099,000 for the three months ended September 30, 2013. Our effective tax rate was 34.9% for the three months ended September 30, 2014 as compared to 38.4% for the three months ended September 30, 2013.

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Comparison of the Nine Months Ended September 30, 2014 and 2013

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $232,041,000, or 176%, to $364,135,000 for the nine months ended September 30, 2014 from $132,094,000 for the nine months ended September 30, 2013. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 11,092 BOE/d to 17,367 BOE/d during the nine months ended September 30, 2014 from 6,275 BOE/d during the nine months ended September 30, 2013. The total increase in revenue of approximately $232,041,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,333,886 Bbls of oil, 412,142 Bbls of natural gas liquids and 1,693,334 Mcf of natural gas for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. The net dollar effect of the decreases in prices of approximately $8,486,000 (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $240,527,000 (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(2.36)	3,596,983	$(8,498)
Natural gas liquids	$(2.77)	661,160	$(1,828)
Natural gas	$0.64	2,899,097	$1,840
Total revenues due to change in price			$(8,486)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	2,333,886	$94.51	$220,571
Natural gas liquids	412,142	$33.49	$13,802
Natural gas	1,693,334	$3.63	$6,154
Total revenues due to change in production volumes			$240,527
Total change in revenues			$232,041

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

Lease Operating Expense. Lease operating expense, or LOE, was $32,216,000 ($6.79 per BOE) for the nine months ended September 30, 2014, an increase of $16,849,000, or 110%, from $15,367,000 ($8.97 per BOE) for the nine months ended September 30, 2013. The increase is due to increased drilling activity and acquisitions, which resulted in additional producing wells for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. On a per BOE basis, LOE declined as new volumes came on line and expenses were held in line or were reduced. By the end of 2013, we were moving approximately 70% of our produced water by pipeline directly into commercial salt water disposal wells, rather than by truck, thereby further reducing one of our largest components of LOE.

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Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $23,350,000 for the nine months ended September 30, 2014 from $8,295,000 for the nine months ended September 30, 2013. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During the nine months ended September 30, 2014, our production taxes per BOE decreased by $0.03 as compared to the nine months ended September 30, 2013. Our ad valorem taxes have increased primarily as a result of increased valuations on our properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased $73,388,000, or 171%, from $42,976,000 for the nine months ended September 30, 2013 to $116,364,000 for the nine months ended September 30, 2014.

The following table provides components of our DD&A expense for the periods presented:

	Nine Months Ended September 30,	
	2014	2013
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$115,437	$42,411
Depreciation of other property and equipment	927	565
DD&A	$116,364	$42,976
Oil and natural gas properties DD&A per BOE	$24.39	$24.76
Total DD&A per BOE	$24.54	$25.09

The increases in depletion of proved oil and natural gas properties of $73,026,000 for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013 resulted primarily from higher total production levels, increased net book value on new reserves added and an increase in capitalized interest to the full cost pool. On a per BOE basis, DD&A decreased primarily due to the increased net book value on new reserves and acquisitions.

General and Administrative Expense. General and administrative expense increased $7,773,000 from $7,213,000 for the nine months ended September 30, 2013 to $14,986,000 for the nine months ended September 30, 2014. The increase was due to increases in stock based compensation, salary, legal, common stock offering, professional service and advisory service expenses. These increases were partially offset by increases in general and administrative costs related to exploration and development activity capitalized to the full cost pool and increases in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the nine months ended September 30, 2014 was $24,090,000 as compared to $2,108,000 for the nine months ended September 30, 2013, an increase of $21,982,000. This increase was due primarily to the issuance of $450.0 million in aggregate principal amount of our 7.625% senior notes in September 2013.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Loss on derivative instruments, net.” For the nine months ended September 30, 2014 and 2013, we had a cash loss on settlement of derivative instruments of $6,207,000 and $5,614,000, respectively. For the nine months ended September 30, 2014 and 2013, we had a non-cash gain on open derivative instruments of $5,630,000 and $3,733,000, respectively.

Income Tax Expense. We recorded income tax expense of $52,742,000 for the nine months ended September 30, 2014 as compared to $20,063,000 for the nine months ended September 30, 2013. Our effective tax rate was 35.4% for the nine months ended September 30, 2014 as compared to 36.8% for the nine months ended September 30, 2013.

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Liquidity and Capital Resources

Our primary sources of liquidity have been proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of the senior notes and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. As we pursue reserves and production growth, we regularly consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us.

Liquidity and Cash Flow

Our cash flows for the nine months ended September 30, 2014 and 2013 are presented below:

	Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Net cash provided by operating activities	$251,995	$91,647
Net cash used in investing activities	(1,289,081)	(830,172)
Net cash provided by financing activities	$1,062,175	$765,267
Net change in cash	$25,089	$26,742

Operating Activities

Net cash provided by operating activities was $252.0 million for the nine months ended September 30, 2014 as compared to $91.6 million for the nine months ended September 30, 2013. The increase in operating cash flows is a result of increases in our oil and natural gas revenues due to production growth and lower expenses in 2014.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. 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.
See “—Sources of our revenue” above.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $1,289.1 million and $830.2 million during the nine months ended September 30, 2014 and 2013, respectively.

During the nine months ended September 30, 2014, we spent $313.9 million on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 61 gross (49 net) horizontal wells, 31 gross (25 net) vertical wells and participated in the drilling of an additional three gross (one net) non-operated wells. We spent an additional $840.5 million on leasehold costs and $43.2 million for the purchase of other property and equipment. On February 27 and 28, 2014, we completed acquisitions of additional oil and natural gas leasehold interests in Martin County, Texas, in the Permian Basin, from unrelated third party sellers for an aggregate purchase price of approximately $292.2 million, subject to certain adjustments. On August 25, 2014, we completed an acquisition of surface rights in the Permian Basin from unrelated third party sellers for a purchase price of approximately $41.9 million. On September 9, 2014, we completed the acquisition of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas in the Permian Basin, for an aggregate purchase price of approximately $523.3 million, subject to certain adjustments. We spent approximately $57.7 million on acquisitions of mineral interests underlying approximately 10,565 gross (3,461) net acres in the Midland and Delaware basins and approximately $33.9 million for a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests.

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During the nine months ended September 30, 2013, we spent $190.1 million on capital expenditures in conjunction with our drilling program in which we drilled 59 gross (51 net) wells and participated in the drilling of an additional four gross (two net) non-operated wells. We spent an additional $440.0 million on the acquisition of mineral interests, $176.3 million on leasehold costs, $5.0 million for the purchase of other property and equipment, $0.3 million, net, on the settlement of non-hedge derivative instruments and $18.6 million for the post-closing adjustment associated with our acquisition of Gulfport Energy Corporation’s oil and natural gas assets in the Permian Basin in connection with our initial public offering in October 2012.

Our investing activities for the nine months ended September 30, 2014 and 2013 are summarized in the following table:

	Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Drilling, completion and infrastructure	$(313,856)	$(190,084)
Acquisition of leasehold interests	(840,482)	(176,346)
Acquisition of Gulfport properties	—	(18,550)
Acquisition of mineral interests	(57,688)	(440,000)
Purchase of other property and equipment	(43,215)	(4,965)
Proceeds from sale of property and equipment	11	62
Cost method investment	(33,851)	—
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	$(1,289,081)	$(830,172)

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2014 was $1,062.2 million as compared to $765.3 million during the same period in 2013. The 2014 amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering, net proceeds of $137.2 million from the Viper Offering, net proceeds of $485.0 million from our July 2014 equity offering, net proceeds of $95.1 million from the Viper September 2014 equity offering and borrowings, net of repayment, of $130.0 million under our credit facility. During the nine months ended September 30, 2013, the amount provided by financing activities was primarily attributable to the net proceeds of $144.4 million from our May 2013 equity offering, $177.5 million from our August 2013 equity offering, $450.0 million from our September 2013 senior note offering and borrowings of $49.0 million under our revolving credit facility, which were repaid with proceeds from the May 2013 offering. In both periods, these proceeds were used primarily to acquire property and fund our drilling costs.

Senior Notes

On September 18, 2013, we completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021, which we refer to as the senior notes. The senior notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014, and will mature on October 1, 2021. On June 23, 2014, in connection with the Viper Offering, we designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries and, upon such designation, Viper Energy LLC, which was a guarantor under the indenture governing of the Senior Notes, was released as a guarantor under the indenture. As of September 30, 2014, the Senior Notes are fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The net proceeds from the senior notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. The senior notes were issued to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act.

The senior notes were issued under, and are governed by, an indenture among us, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee, as amended and supplemented, or the Indenture. We may issue additional senior notes under the Indenture, and all senior notes issued under the Indenture will constitute part of a single class of securities for all purposes of the Indenture. The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of 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, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries. If we experience certain kinds of changes of control or if we sell certain of our assets, holders of the senior notes may have the right to require us to repurchase their senior notes.

We have the option to redeem the senior notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, we may redeem all or a part of the senior notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a “make-whole” premium at the redemption date. Furthermore, before October 1, 2016, we may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the senior notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the senior notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

In connection with the issuance of the senior notes, we and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on September 18, 2013, pursuant to which we and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the senior notes for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on September 15, 2014. The exchange offer was completed on October 23, 2014.

Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, with a syndication of banks, including Wells Fargo, as administrative agent, sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $600.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2014, the borrowing base was set at $350.0 million and we had outstanding borrowings of $140.0 million and $210.0 million available for future borrowings under this facility. Our weighted-average interest rate on borrowings under our credit facility was 1.64% during the nine months ended September 30, 2014. Our lead lender recently approved an increase in our borrowing base to $750.0 million, however we have elected to limit the lenders’ aggregate commitment to $500.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.50% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds 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, 2018.

On June 9, 2014, we entered into a first amendment to the second amended and restated credit agreement, dated November 1, 2013. This amendment modified certain provisions of the credit agreement to, among other things, allow us to designate one or more of our subsidiaries as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, we designated the

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Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries under the credit agreement. As of September 30, 2014, the loan is guaranteed by us, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of our assets and the assets of Diamondback O&G LLC and the guarantors.

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750 million in the form of senior or senior subordinated 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, 2014, we had $450 million of senior notes outstanding.

As of September 30, 2014, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our 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 revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Partnership Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership’s oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2014, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of September 30, 2014.

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

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

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

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

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2014 capital budget for drilling and infrastructure of $425.0 million to $475.0 million, representing an increase of 48% over 2013. We estimate that, of these expenditures, approximately:

- 85% will be spent on 65 to 75 gross (52 to 60 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;
- 8% will be spent on 20 to 25 gross (16 to 20 net) operated vertical wells focused in Midland County;
- 5% will be spent on infrastructure; and
- 2% will be spent on non-operated drilling.

During the nine months ended September 30, 2014, our aggregate capital expenditures for drilling and infrastructure were $313.9 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2014, we spent approximately $840.5 million on acquisitions of leasehold interests.

The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Based upon current oil and natural gas price and production expectations for 2014, we believe that our cash flow from operations and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2014. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. Further, our 2014 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

We monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control. If we require additional capital, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financing, asset sales, offerings of debt and or equity securities or other means. We cannot assure you that the needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

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Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013.

Recent Accounting Pronouncements

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

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2014.

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, 2013.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

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

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. With respect to these fixed price swap contracts, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing.

At September 30, 2014, we had a net asset derivative position of $6,061,000, related to our Argus Louisiana Light Sweet fixed price swaps, as compared to a net asset derivative position of $431,000 as of December 31, 2013 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of September 30, 2014, a 10% increase in forward curves associated with the underlying commodity would have decrease the net asset position into a net liability derivative position of $2,986,000 a decrease of $9,047,000, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $15,108,000 an increase of $9,047,000. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Subsequent to September 30, 2014, we entered into additional commodity contracts. The contracts are fixed price oil swaps that will settle against the weighted average price per barrel of Argus Louisiana light sweet or NYMEX West Texas Intermediate during the calculation period. The following table presents the terms of the contracts:

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	Volumes (Bbls)	Fixed Swap Price	Production Period		
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	183,000	$82.95	November 2014		December 2014
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	1,095,000	$90.99	January 2015	-	December 2015
Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap	1,825,000	$84.10	January 2015	-	December 2015
Crude Oil—ICE Brent Fixed Price Swap	640,000	$88.78	February 2015	-	January 2016
Crude Oil—ICE Brent Fixed Price Swap	91,000	$88.72	January 2016	-	February 2016

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $37.7 million at September 30, 2014) and receivables from the sale of our oil and natural gas production (approximately $$50.6 million at September 30, 2014).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the nine months ended September 30, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (66%); and Enterprise Crude Oil LLC (17%). For the year ended December 31, 2013, two purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At September 30, 2014, we had two customers that represented approximately 56% of our total joint operations receivables. At December 31, 2013, we had one customer that represented approximately 86% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Our weighted-average interest rate on borrowings from our credit facility was 1.64% during the nine months ended September 30, 2014. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $140,000 based on the $140.0 million outstanding in the aggregate under our revolving credit facility on September 30, 2014.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and

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procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of September 30, 2014, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of 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 our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of September 30, 2014, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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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, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A.RISK FACTORS.

Our business faces many risks. Any of the risks discussed in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

In addition to the information set forth in this Form 10–Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10–K for the year ended December 31, 2013. 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, 2013.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
2.1#	Purchase and Sale Agreement dated February 14, 2014, between Henry Resources LLC, Henry Production LLC, Henry Taw Production LP, Davlin LP, Good Providence LP, William R. Fair, UTH Investments LTD, Paloma Oil & Ranch LP, Chinati Oil & Ranch LP, J. Craig Corbett, Bambana Resources LP, and FC Permian Properties, Inc., as Sellers, and Diamondback E&P LLC, as Buyer (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 18, 2014).
2.2#	Purchase and Sale Agreement, dated February 14, 2014, between Henry Resources LLC, Henry Production LLC, Henry Taw Production LP, Davlin LP, Good Providence LP, William R. Fair, UTH Investments LTD, Paloma Oil & Ranch LP, Chinati Oil & Ranch LP, J. Craig Corbett, Bambana Resources LP, FC Permian Properties, Inc., Blake Braun, Richard D. Campbell, and Thomas J. Woodside, as Sellers, and Diamondback E&P LLC, as Buyer (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 18, 2014).
2.3#	Purchase and Sale Agreement by and among Rio Oil and Gas, LLC, Rio Oil and Gas (Permian) LLC, Rio Oil and Gas (OPCO), LLC, Bluestem Energy, LP, Bluestem Energy Partners, LP, Bluestem Energy Holdings, LLC, Bluestem Energy Assets, LLC, Bluestem Acquisitions, LLC, BC Operating, Inc., Crown Oil Partners V, LP and Crump Energy Partners II, LLC, as sellers, and Diamondback E&P LLC, as buyer, dated July 18, 2014 (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on July 21, 2014).
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).

4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).

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Exhibit Number	Description
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.4	Indenture, dated as of September 18, 2013, among Diamondback Energy, Inc., the subsidiary guarantors party thereto and Wells Fargo, N.A., as trustee (including the form of Diamondback Energy, Inc.'s 7.625% Senior Note due October 2021 (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 18, 2013).
4.5	First Supplemental Indenture, dated as of November 5, 2013, by and between Diamondback Energy, the subsidiary guarantors party thereto and Wells Fargo, N.A, as trustee (incorporated by reference to Exhibit 4.5 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 19, 2014).
4.6	Registration Rights Agreement, dated as of September 18, 2013, among Diamondback Energy, Inc., the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 18, 2013).
10.1	Senior Secured Revolving Credit Agreement, dated as of July 8, 2014, among Viper Energy Partners LP, as borrower, Wells Fargo Bank, National Association, as the administrative agent, sole book runner and lead arranger, and certain lenders from time to time party thereto. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-36505, filed by Viper Energy Partners LP on July 14, 2014).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer of the Registrant 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.
32.2++	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission upon request.

* Filed herewith.

++ The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Quarterly Report on Form 10-Q pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed "filed" by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

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SIGNATURES

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

DIAMONDBACK ENERGY, INC.

Date: November 6, 2014

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer
(Principal Executive Officer)

/s/ Teresa L. Dick
Teresa L. Dick
Chief Financial Officer
(Principal Financial and Accounting Officer)