Diamondback Energy, Inc.
Form 10-Q
May 07, 2015
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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 March 31, 2015
OR
o 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	o

Non-Accelerated Filer	o	Smaller Reporting Company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
As of May 5, 2015, 59,009,236 shares of the registrant’s common stock were outstanding.

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.

Brent. Brent sweet light crude oil.

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.

LLS. Light Louisiana sweet crude oil.

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.
WTI. West Texas Intermediate, also known as Texas light sweet crude oil.

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 report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “contin “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, 2014 could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- 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 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 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)

	March 31, 2015	December 31, 2014
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$31,643	$30,183
Restricted cash	500	500
Accounts receivable:		
Joint interest and other	44,563	50,943
Oil and natural gas sales	38,647	43,050
Related party	—	4,001
Inventories	2,847	2,827
Derivative instruments	92,335	115,607
Prepaid expenses and other	4,837	4,600
Total current assets	215,372	251,711
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($737,197 and $773,520 excluded from amortization at March 31, 2015 and December 31, 2014, respectively)	3,211,981	3,118,597
Pipeline and gas gathering assets	7,174	7,174
Other property and equipment	48,338	48,180
Accumulated depletion, depreciation, amortization and impairment	(441,821)	(382,144)
	2,825,672	2,791,807
Derivative instruments	—	1,934
Other assets	51,437	50,029
Total assets	$3,092,481	$3,095,481
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$8,801	$26,230
Accrued capital expenditures	75,272	129,397
Other accrued liabilities	50,952	41,149
Revenues and royalties payable	16,546	30,000
Deferred income taxes	32,459	39,953
Total current liabilities	184,030	266,729
Long-term debt	611,579	673,500
Asset retirement obligations	8,844	8,447
Deferred income taxes	171,511	161,592
Total liabilities	975,964	1,110,268
Contingencies (Note 14)		
Stockholders' equity:		

Common stock, $0.01 par value, 100,000,000 shares authorized, 59,008,403 issued and outstanding at March 31, 2015; 57,887,583 issued and outstanding at December 31, 2014	590	569
Additional paid-in capital	1,680,394	1,554,174
Retained earnings	202,117	196,268
Total Diamondback Energy, Inc. stockholders' equity	1,883,101	1,751,011
Noncontrolling interest	233,416	234,202
Total equity	2,116,517	1,985,213
Total liabilities and equity	$3,092,481	$3,095,481

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands, except per share amounts)	
Revenues:		
Oil sales	$92,916	$89,758
Natural gas sales	1,708	1,755
Natural gas sales - related party	2,640	1,580
Natural gas liquid sales	1,593	2,584
Natural gas liquid sales - related party	2,544	2,327
Total revenues	101,401	98,004
Costs and expenses:		
Lease operating expenses	22,456	7,807
Lease operating expenses - related party	—	108
Production and ad valorem taxes	8,242	5,578
Production and ad valorem taxes - related party	153	264
Gathering and transportation	61	214
Gathering and transportation - related party	969	368
Depreciation, depletion and amortization	59,677	30,973
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $4,924 and $2,190 for the three months ended March 31, 2015 and 2014, respectively)	7,751	4,265
General and administrative expenses - related party	485	292
Asset retirement obligation accretion expense	170	72
Total costs and expenses	99,964	49,941
Income from operations	1,437	48,063
Other income (expense)		
Interest expense	(10,497)	(6,505)
Other income	492	—
Other income - related party	23	30
Gain (loss) on derivative instruments, net	18,354	(4,398)
Total other income (expense), net	8,372	(10,873)
Income before income taxes	9,809	37,190
Provision for income taxes		
Current	945	—
Deferred	2,425	13,601
Net income	6,439	23,589
Less: Net income attributable to noncontrolling interest	590	—
Net income attributable to Diamondback Energy, Inc.	$5,849	$23,589
Earnings per common share		
Basic	$0.10	$0.49
Diluted	$0.10	$0.48
Weighted average common shares outstanding		

Basic	58,386	48,447
Diluted	58,626	48,867

See accompanying notes to combined consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings/ (Accumulated Deficit)	Non-controlling Interest	Total
Balance December 31, 2013	47,106	$471	$842,557	$2,513	$ —	$845,541
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	—	—
Unit-based compensation	—	—	—	—	—	—
Distribution to non-controlling interest	—	—	—	—	—	—
Stock based compensation	—	—	3,256	—	—	3,256
Tax benefits related to stock-based compensation	—	—	—	—	—	—
Common shares issued in public offering, net of offering costs	3,450	35	208,410	—	—	208,445
Exercise of stock options and vesting of restricted stock units	145	2	2,076	—	—	2,078
Equity payment- Wexford Advisory Services (See Note 11)	—	—	—	—	—	—
Net income	—	—	—	23,589	—	23,589
Balance March 31, 2014	50,701	$508	$1,056,299	$26,102	$ —	$1,082,909
Balance December 31, 2014	56,888	$569	$1,554,174	$196,268	$ 234,202	$1,985,213
Unit-based compensation	—	—	—	—	939	939
Stock-based compensation	—	—	6,125	—	—	6,125
Distribution to noncontrolling interest	—	—	—	—	(2,315)	(2,315)
Common shares issued in public offering, net of offering costs	2,012	20	119,208	—	—	119,228
Exercise of stock options and vesting of restricted stock units	108	1	887	—	—	888
Net income	—	—	—	5,849	590	6,439
Balance March 31, 2015	59,008	$590	$1,680,394	$202,117	$ 233,416	$2,116,517

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income	$6,439	$23,589
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	2,425	13,601
Asset retirement obligation accretion expense	170	72
Depreciation, depletion, and amortization	59,677	30,973
Amortization of debt issuance costs	630	458
Change in fair value of derivative instruments	25,206	3,342
Stock based compensation expense	4,924	2,190
(Gain) loss on sale of assets, net	—	(11)
Changes in operating assets and liabilities:		
Accounts receivable	7,005	(12,490)
Accounts receivable-related party	—	(995)
Inventories	(20)	(258)
Prepaid expenses and other	(237)	(311)
Accounts payable and accrued liabilities	(16,226)	7,590
Accounts payable and accrued liabilities-related party	14,128	296
Accrued interest	8,476	—
Revenues and royalties payable	(13,454)	3,420
Net cash provided by operating activities	99,143	71,466
Cash flows from investing activities:		
Additions to oil and natural gas properties	(144,397)	(84,211)
Additions to oil and natural gas properties-related party	(7,000)	(1,650)
Acquisition of leasehold interests	(2,000)	(312,207)
Pipeline and gas gathering assets	—	(532)
Purchase of other property and equipment	(158)	(595)
Proceeds from sale of property and equipment	—	11
Net cash used in investing activities	(153,555)	(399,184)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	57,501	127,000
Repayment on credit facility	(119,422)	—
Debt issuance costs	(8)	(82)
Public offering costs	(194)	(75)
Proceeds from public offerings	119,422	208,644
Exercise of stock options	888	1,990
Distribution to non-controlling interest	(2,315)	—
Net cash provided by financing activities	55,872	337,477
Net increase in cash and cash equivalents	1,460	9,759
Cash and cash equivalents at beginning of period	30,183	15,555
Cash and cash equivalents at end of period	$31,643	$25,314

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

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$1,389	$149
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$102	$214
Asset retirement obligation revisions in estimated liability	$78	$588
Asset retirement obligation acquired	$47	$1,294
Change in accrued capital expenditures	$(45,854)	$(6,932)
Capitalized stock based compensation	$2,139	$1,066

See accompanying notes to combined 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 March 31, 2015, 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 March 31, 2015, 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, 2014, 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.

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

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

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.

New Accounting Pronouncements

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

In April 2015, the Financial Accounting Standards Board issued ASU 2015-03, "Interest—Imputation of Interest". ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued.

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 with the net proceeds of the July 2014 equity offering discussed in Note 9 below and borrowings under the Company's revolving credit facility discussed in Note 8 below.

There were no material changes from the purchase price allocation disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The Company has included in its combined consolidated statements of operations revenues of $5.3 million and direct operating expenses of $3.7 million for the three months ended March 31, 2015 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

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 with the net proceeds of the February 2014 equity offering discussed in Note 9 below and

borrowings under the Company’s revolving credit facility discussed in Note 8 below.
There were no material changes from the purchase price allocation disclosed in the Company’s Annual Report on Form 10-K for the year ended December 31, 2014.
The Company has included in its combined consolidated statements of operations revenues of $6.8 million and direct operating expenses of $3.0 million for the three months ended March 31, 2015 and operations revenues of

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

$4.9 million and direct operating expenses of $1.1 million for the period from February 28, 2014 to March 31, 2014, due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

Pro Forma Financial Information

The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three months ended March 31, 2014 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.

	Pro Forma (Unaudited) Three Months Ended March 31, 2014
	(in thousands)
Revenues	$119,944
Income from operations	54,698
Net income	27,797

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 March 31, 2015, 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.

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. 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. During the three months ended March 31, 2015, the Partnership distributed $17.6 million to Diamondback in respect of its common units.

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 11—Related Party Transactions for details of the advisory services agreement the Partnership and General Partner entered into with Wexford Capital LP ("Wexford").

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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 8—Debt for a description of this credit facility.

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	March 31, 2015	December 31, 2014
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$2,474,784	$2,345,077
Not subject to depletion-acquisition costs		
Incurred in 2015	3,906	—
Incurred in 2014	563,091	576,802
Incurred in 2013	106,139	130,474
Incurred in 2012	63,297	65,480
Incurred in 2011	764	764
Total not subject to depletion	737,197	773,520
Gross oil and natural gas properties	3,211,981	3,118,597
Less accumulated depletion	(438,720)	(379,481)
Oil and natural gas properties, net	2,773,261	2,739,116
Pipeline and gas gathering assets	7,174	7,174
Other property and equipment	48,338	48,180
Less accumulated depreciation	(3,101)	(2,663)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$2,825,672	$2,791,807

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 $4.7 million and $2.3 million for the three months ended March 31, 2015 and 2014, 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:

	Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Asset retirement obligation, beginning of period	$8,486	$3,029
Additional liability incurred	102	214
Liabilities acquired	47	1,294
Liabilities settled	—	(10)
Accretion expense	170	72
Revisions in estimated liabilities	78	588
Asset retirement obligation, end of period	8,883	5,187
Less current portion	39	40
Asset retirement obligations - long-term	$8,844	$5,147

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. EQUITY METHOD INVESTMENTS

In October 2014, the Company paid $0.6 million for a minority interest in an entity that was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. The board of this entity may also authorize the entity to offer these services to other counties in the Permian Basin and to pursue other business opportunities. The Company has committed to invest an aggregate amount of $5.0 million in this entity, and several other third parties have committed to invest an aggregate of $15.0 million. The Company will retain a minority interest after all commitments are received. The entity was formed as a limited liability company and maintains a specific ownership account for each investor, similar to a partnership capital account structure. Therefore the Company accounts for this investment under the equity method of accounting.

8. DEBT

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

	March 31, 2015	December 31, 2014
	(in thousands)	
Revolving credit facility	$161,579	$223,500
7.625 % Senior Notes due 2021	450,000	450,000
Partnership revolving credit facility	—	—
Total long-term debt	$611,579	$673,500

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 March 31, 2015, 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 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 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

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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
On June 9, 2014, Diamondback entered into a first amendment (the "first amendment") and on November 13, 2014, Diamondback entered into a second amendment (the "second 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 March 31, 2015, 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 second amendment increased the maximum amount of the credit facility to $2.0 billion, modified the dates and deadlines of the credit agreement relating to the scheduled borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors (the "borrowing base") and added new provisions that allow the Company to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2015, the borrowing base was set at $750.0 million, of which the Company had elected a commitment amount of $500.0 million, and the Company had outstanding borrowings of $161.6 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.

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

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 March 31, 2015, the Company had $450.0 million of senior unsecured notes outstanding.

As of March 31, 2015 and December 31, 2014, 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 March 31, 2015, the borrowing base was set at $110.0 million. The Partnership had no outstanding borrowings as of March 31, 2015.

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.

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Diamondback Energy, Inc. and Subsidiaries
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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.

9. CAPITAL STOCK AND EARNINGS PER SHARE

As of March 31, 2015, Diamondback had completed the following equity offerings since January 1, 2014:

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.

In July 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.

In January 2015, the Company completed an underwritten public offering of 1,750,000 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and the Company received net proceeds of approximately $119.4 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:

	Three Months Ended March 31, 2015		
	Income	Shares	Per Share
	(in thousands, except per share amounts)		
Basic:			
Net income attributable to common stock	$5,849	58,386	$0.10
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	240	
Diluted:			
Net income attributable to common stock	$5,849	58,626	$0.10

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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	Three Months Ended March 31, 2014		
	Income	Shares	Per Share
	(in thousands, except per share amounts)		
Basic:			
Net income attributable to common stock	$23,589	48,447	$0.49
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	420	
Diluted:			
Net income attributable to common stock	$23,589	48,867	$0.48

10. STOCK AND UNIT BASED COMPENSATION

The following table presents the effects of the equity and stock based compensation plans and related costs:

	2015	2014
General and administrative expenses	$4,924	$2,190
Stock based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	2,139	1,066
Related income tax benefit	770	384

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.

Stock Options

The following table presents the Company’s stock option activity under the 2012 Plan for the three months ended March 31, 2015.

Diamondback Energy, Inc. and Subsidiaries
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	Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	313,105	$18.29		
Granted	—	$—		
Exercised	(46,750)	$19.00		
Expired/Forfeited	—	$—		
Outstanding at March 31, 2015	266,355	$18.16	1.73	$11,097
Vested and Expected to vest at March 31, 2015	266,355	$18.16	1.73	$11,097
Exercisable at March 31, 2015	34,855	$17.84	1.62	$1,474

The aggregate intrinsic value of stock options that were exercised during the three months ended March 31, 2015 and 2014 was $2,129,000 and $5,310,000, respectively. As of March 31, 2015, the unrecognized compensation cost related to unvested stock options was $453,000. Such cost is expected to be recognized over a weighted-average period of 1.1 years.

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the three months ended March 31, 2015.

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	167,291	$49.99
Granted	90,252	$68.46
Vested	(63,136)	$56.43
Forfeited	(821)	$74.97
Unvested at March 31, 2015	193,586	$49.82

The aggregate fair value of restricted stock units that vested during the three months ended March 31, 2015 and 2014 was $4,074,000 and $2,003,000, respectively. As of March 31, 2015, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $7,987,000. Such cost is expected to be recognized over a weighted-average period of 1.5 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. In February 2015, eligible employees received additional performance restricted stock unit awards totaling 90,249 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, 2014 to December 31, 2016 and cliff vest at December 31, 2016.

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 for the February 2014 award.

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Notes to Consolidated Financial Statements-(Continued)
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	2015	
Grant-date fair value	$ 125.63	
Risk-free rate	0.30	%
Company volatility	39.60	%

The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions for the February 2015 award.

	2015	
Grant-date fair value	$ 137.14	
Risk-free rate	0.49	%
Company volatility	43.36	%

The following table presents the Company’s performance restricted stock units activity under the 2012 Plan for the three months ended March 31, 2015.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	79,150	$ 125.63
Granted	90,249	$ 137.14
Vested	—	$—
Forfeited	—	$—
Unvested at December 31, 2014 (1)	169,399	$ 131.76

(1) A maximum of 338,798 units could be awarded based upon the Company’s final TSR ranking.

As of March 31, 2015, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $15,459,000. Such cost is expected to be recognized over a weighted-average period of 1.5 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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Diamondback Energy, Inc. and Subsidiaries
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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 three months ended March 31, 2015.

	Unit Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	2,500,000	$26.00		
Granted	—	$—		
Outstanding at March 31, 2015	2,500,000	$26.00	2.22	$—
Vested and Expected to vest at March 31, 2015	2,500,000	$26.00	2.22	$—
Exercisable at March 31, 2015	—	$—	—	$—

As of March 31, 2015, the unrecognized compensation cost related to unvested unit options was $7.8 million. Such cost is expected to be recognized over a weighted-average period of 2.2 years.

Phantom Units

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

The following table presents the phantom unit activity under the Viper LTIP for the three months ended March 31, 2015.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	17,776	$19.51
Granted	—	$—
Vested	—	$—
Forfeited	—	$—
Unvested at March 31, 2015	17,776	$19.51

As of March 31, 2015, the unrecognized compensation cost related to unvested phantom units was $0.3 million. Such cost is expected to be recognized over a weighted-average period of 1.2 years.

11. RELATED PARTY TRANSACTIONS

Administrative Services

Diamondback Energy, Inc. and Subsidiaries
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An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement that 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 ended March 31, 2015 and 2014, the Company incurred total costs of $0 and $1,000, 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. The Company had no outstanding amounts payable at March 31, 2015 and December 31, 2014.

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 ended March 31, 2015 and 2014, the affiliate reimbursed the Company $0 and $30,000, respectively, for services under the shared services agreement. The Company had no outstanding amounts payable at March 31, 2015 and December 31, 2014.

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 March 31, 2015, 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 ended March 31, 2015 and 2014, the Company incurred total costs for services performed by Bison of $7,000 and $1,510,000, respectively. The Company had no outstanding amounts payable to Bison as of March 31, 2015 and December 31, 2014.

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. The Company incurred no costs and $248,000 for services performed for the three months ended March 31, 2015 and 2014, respectively. The Company had no outstanding amounts payable to Panther Drilling as of March 31, 2015 and December 31, 2014.

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, 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. An entity controlled by Wexford had owned an approximately 28% equity interest in Coronado Midstream until Coronado Midstream was sold in March 2015. Coronado Midstream is no longer a related party. The Company recognized revenues from Coronado Midstream of $5,184,000 and $3,907,000 for the three months ended March 31, 2015 and 2014, respectively. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream of $1,122,000 and $632,000 for the three

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months ended March 31, 2015 and 2014, respectively. As of December 31, 2014, Coronado Midstream owed the Company $3,986,000 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 did not purchase sand from Muskie during either the three months ended March 31, 2015 or 2014. The Company had no outstanding amounts payable to Muskie as of March 31, 2015 or December 31, 2014.

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 $184,000 and $93,000 for the three months ended March 31, 2015 and 2014, 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. In the second and fourth quarters of 2014, the Company amended this agreement to further increase the size of the leased premises. The monthly rent increased from $25,000 to $27,000 in the second quarter of 2014 and from $27,000 to $53,000 in the fourth quarter of 2014. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term. In November 2014, the Company further amended the lease, including extending the term of the lease for an additional ten-year period. In April 2015, the Company again amended this lease to increase the size of the leased premises. The monthly rent for the additional space is $23,000. Upon commencement of the extension in June 2016, the monthly base rent will increase to $94,000, with an increase of approximately 2% annually.

Field Office Lease

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 $39,000 to the related party for the three months ended March 31, 2015. 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 $0 and $64,000 for the three months ended March 31, 2015 and 2014, 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

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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 $137,000 and $125,000 for the three months ended March 31, 2015 and 2014, respectively, under the Advisory Services Agreement. As of March 31, 2015 and December 31, 2014, the Company had no outstanding amounts payable to Wexford 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 ended March 31, 2015, the Partnership incurred costs of $125,000 under the agreement. As of March 31, 2015 and December 31, 2014, the Partnership had no outstanding amounts payable to Wexford.

12. 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 combined 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, New York Mercantile Exchange West Texas

Intermediate pricing or Inter–Continental Exchange (“ICE”) pricing for Brent crude oil.
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.

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As of March 31, 2015, 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
April- December 2015	855,000	91.31

Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April - December 2015	1,375,000	84.10

Crude Oil—ICE Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April - December 2015	550,000	88.78
January - February 2016	91,000	88.72

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 March 31, 2015 and December 31, 2014.

	March 31, 2015		
	(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	$92,335	$—	$92,335

	December 31, 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	$117,541	$—	$117,541

Diamondback Energy, Inc. and Subsidiaries
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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:

	March 31, 2015	December 31, 2014
	(in thousands)	
Current Assets: Derivative instruments	$92,335	$115,607
Noncurrent Assets: Derivative instruments	—	1,934
Total Assets	$92,335	$117,541

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 combined consolidated statements of operations:

	March 31, 2015	December 31, 2014
Change in fair value of open non-hedge derivative instruments	$(25,206)	$(3,342)
Gain (loss) on settlement of non-hedge derivative instruments	43,560	(1,056)
Gain (loss) on derivative instruments	$18,354	$(4,398)

13. 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 March 31, 2015 and December 31, 2014.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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	Fair value measurements at March 31, 2015 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	$—	$92,335	$—	$92,335

	Fair value measurements at December 31, 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	$—	$117.541	$—	$117.541

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 balance sheets.

	March 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$161,579	$161,579	$223,500	$10,000
7.625% Senior Notes due 2021	450,000	477,563	450,000	440,438
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 March 31, 2015 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 March 31, 2015.

14. COMMITMENTS AND CONTINGENCIES
Lease Commitments
The following is a schedule of minimum future lease payments with commitments that have initial or remaining noncancelable lease terms in excess of one year as of March 31, 2015:

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Notes to Consolidated Financial Statements-(Continued)
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Year Ending December 31,	Drilling Rig Commitments	Office and Equipment Leases
2016	27,317	$1,583
2017	19,892	1,734
2018	13,031	1,649
2019	—	1,509
2020	—	1,324
Thereafter	—	7,641
Total	60,240	$15,440

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.

15. SUBSEQUENT EVENTS

Since January 1, 2015, the Company has acquired or has entered into definitive purchase agreements to acquire from unrelated third party sellers an aggregate of approximately 15,940 gross (11,948 net) acres in the Midland Basin, primarily in northwest Howard County, in the Permian Basin, for an aggregate purchase price of approximately $437.8 million, subject to certain adjustments. The Company has offered an average approximate 1.5% overriding royalty interest in certain of the acreage subject to these acquisitions to the Partnership for $33.7 million. This offer is subject to the approval of the conflicts committee of the Partnership’s general partner and the Company’s completion of the acquisitions, and there can be no assurance that this transaction will be completed on these terms or at all. The Company intends to finance the acquisitions, subject to market conditions and other factors, primarily with proceeds from one or more capital market transactions, which may include debt or equity offerings. The Company anticipates that all of these acquisitions will be completed by the end of June 2015. However, substantially all of the transactions remain subject to completion of due diligence and satisfaction of other closing conditions. There can be no assurance that the Company will acquire all or any portion of the acreage described above.

16. 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 combined 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.

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

Condensed Consolidated Balance Sheet
March 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$54	$21,768	$9,821	$—	$31,643
Restricted cash	—	—	500	—	500
Accounts receivable	—	76,124	7,084	2	83,210
Intercompany receivable	1,798,170	2,466,740	—	(4,264,910)	—
Inventories	—	2,847	—	—	2,847
Other current assets	337	96,343	492	—	97,172
Total current assets	1,798,561	2,663,822	17,897	(4,264,908)	215,372
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	2,700,982	510,999	—	3,211,981
Pipeline and gas gathering assets	—	7,174	—	—	7,174
Other property and equipment	—	48,338	—	—	48,338
Accumulated depletion, depreciation, amortization and impairment	—	(401,507)	(41,700)	1,386	(441,821)
	—	2,354,987	469,299	1,386	2,825,672
Investment in subsidiaries	844,250	—	—	(844,250)	—
Other assets	8,833	7,654	34,950	—	51,437
Total assets	$2,651,644	$5,026,463	$522,146	$(5,107,772)	$3,092,481
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$1	$8,794	$6	$—	$8,801
Intercompany payable	96,230	4,168,678	—	(4,264,908)	—
Other current liabilities	50,801	123,733	695	—	175,229
Total current liabilities	147,032	4,301,205	701	(4,264,908)	184,030
Long-term debt	450,000	161,579	—	—	611,579
Asset retirement obligations	—	8,844	—	—	8,844
Deferred income taxes	171,511	—	—	—	171,511
Total liabilities	768,543	4,471,628	701	(4,264,908)	975,964
Commitments and contingencies					
Stockholders’ equity:	1,883,101	554,835	521,445	(1,076,280)	1,883,101
Noncontrolling interest	—	—	—	233,416	233,416
Total equity	1,883,101	554,835	521,445	(842,864)	2,116,517
Total liabilities and equity	$2,651,644	$5,026,463	$522,146	$(5,107,772)	$3,092,481

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

Condensed Consolidated Balance Sheet
December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$6	$15,067	$15,110	$—	$30,183
Restricted cash	—	—	500	—	500
Accounts receivable	—	85,752	8,239	2	93,993
Accounts receivable - related party	—	4,001	—	—	4,001
Intercompany receivable	1,658,215	2,167,434	—	(3,825,649)	—
Inventories	—	2,827	—	—	2,827
Other current assets	562	119,392	253	—	120,207
Total current assets	1,658,783	2,394,473	24,102	(3,825,647)	251,711
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	2,607,513	511,084	—	3,118,597
Pipeline and gas gathering assets	—	7,174	—	—	7,174
Other property and equipment	—	48,180	—	—	48,180
Accumulated depletion, depreciation, amortization and impairment	—	(351,200)	(32,799)	1,855	(382,144)
	—	2,311,667	478,285	1,855	2,791,807
Investment in subsidiaries	839,217	—	—	(839,217)	—
Other assets	9,155	7,793	35,015	—	51,963
Total assets	$2,507,155	$4,713,933	$537,402	$(4,663,009)	$3,095,481
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$26,224	$6	$—	$26,230
Intercompany payable	95,362	3,730,287	—	(3,825,649)	—
Other current liabilities	49,190	189,264	2,045	—	240,499
Total current liabilities	144,552	3,945,775	2,051	(3,825,649)	266,729
Long-term debt	450,000	223,500	—	—	673,500
Asset retirement obligations	—	8,447	—	—	8,447
Deferred income taxes	161,592	—	—	—	161,592
Total liabilities	756,144	4,177,722	2,051	(3,825,649)	1,110,268
Commitments and contingencies					
Stockholders' equity:	1,751,011	536,211	535,351	(1,071,562)	1,751,011
Noncontrolling interest	—	—	—	234,202	234,202
Total equity	1,751,011	536,211	535,351	(837,360)	1,985,213
Total liabilities and equity	$2,507,155	$4,713,933	$537,402	$(4,663,009)	$3,095,481

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

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$77,384	$—	$15,532	$92,916
Natural gas sales	—	3,779	—	569	4,348
Natural gas liquid sales	—	3,693	—	444	4,137
Royalty income	—	—	16,545	(16,545)	—
Total revenues	—	84,856	16,545	—	101,401
Costs and expenses:					
Lease operating expenses	—	22,456	—	—	22,456
Production and ad valorem taxes	—	7,067	1,328	—	8,395
Gathering and transportation	—	1,030	—	—	1,030
Depreciation, depletion and amortization	—	50,307	8,901	469	59,677
General and administrative expenses	4,518	2,166	1,552	—	8,236
Asset retirement obligation accretion expense	—	170	—	—	170
Total costs and expenses	4,518	83,196	11,781	469	99,964
Income (loss) from operations	(4,518)	1,660	4,764	(469)	1,437
Other income (expense)					
Interest income - intercompany	—	—	—	—	—
Interest expense	(8,910)	(1,419)	(168)	—	(10,497)
Interest expense - intercompany	—	—	—	—	—
Other income	—	29	486	—	515
Gain on derivative instruments, net	—	18,354	—	—	18,354
Total other income (expense), net	(8,910)	16,964	318	—	8,372
Income (loss) before income taxes	(13,428)	18,624	5,082	(469)	9,809
Provision for income taxes	3,370	—	—	—	3,370
Net income (loss)	(16,798)	18,624	5,082	(469)	6,439
Less: Net income attributable to noncontrolling interest	—	—	—	590	590
Net income (loss) attributable to Diamondback Energy, Inc.	$(16,798)	$18,624	$5,082	$(1,059)	$5,849

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

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$74,796	$—	$14,962	$89,758
Natural gas sales	—	2,757	—	578	3,335
Natural gas liquid sales	—	4,144	—	767	4,911
Royalty income	—	—	15,853	(15,853)	—
Total revenues	—	81,697	15,853	454	98,004
Costs and expenses:					
Lease operating expenses	—	7,915	—	—	7,915
Production and ad valorem taxes	—	4,903	921	18	5,842
Gathering and transportation	—	588	—	(6)	582
Depreciation, depletion and amortization	—	25,801	5,567	(395)	30,973
General and administrative expenses	3,985	506	144	(78)	4,557
Asset retirement obligation accretion expense	—	72	—	—	72
Intercompany charges	—	—	—	—	—
Total costs and expenses	3,985	39,785	6,632	(461)	49,941
Income (loss) from operations	(3,985)	41,912	9,221	915	48,063
Other income (expense)					
Interest income	—	—	—	—	—
Interest income - intercompany	5,368	—	—	(5,368)	—
Interest expense	(5,887)	(618)	—	—	(6,505)
Interest expense - intercompany	—	—	(5,368)	5,368	—
Other income	—	—	—	—	—
Other income (expense)- intercompany	—	108	—	(78)	30
Loss on derivative instruments, net	—	(4,398)		—	(4,398)
Total other income (expense), net	(519)	(4,908)	(5,368)	(78)	(10,873)
Income (loss) before income taxes	(4,504)	37,004	3,853	837	37,190
Provision for income taxes	13,601	—	—	—	13,601
Net income (loss)	$(18,105)	$37,004	$3,853	$837	$23,589

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

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided (used in) by operating activities	$(1,970)	$86,560	$14,553	$—	$99,143
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(150,963)	85	—	(150,878)
Acquisition of leasehold interests	—	(2,519)	—	—	(2,519)
Purchase of other property and equipment	—	(158)	—	—	(158)
Intercompany transfers	(16,280)	16,280	—	—	—
Other investing activities	—	—	—	—	—
Net cash provided by (used in) investing activities	(16,280)	(137,360)	85	—	(153,555)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	57,501	—	—	57,501
Repayment on credit facility	—	(119,422)	—	—	(119,422)
Proceeds from public offerings	119,422	—	—	—	119,422
Distribution from subsidiary	17,612	—	—	(17,612)	—
Distribution to non-controlling interest	—	—	(19,927)	17,612	(2,315)
Intercompany transfers	(119,422)	119,422	—	—	—
Other financing activities	686	—	—	—	686
Net cash provided by (used in) financing activities	18,298	57,501	(19,927)	—	55,872
Net increase (decrease) in cash and cash equivalents	48	6,701	(5,289)	—	1,460
Cash and cash equivalents at beginning of period	6	15,067	15,110	—	30,183
Cash and cash equivalents at end of period	$54	$21,768	$9,821	$—	$31,643

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

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$3,323	$67,588	$6,543	$(5,988)	$71,466
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(78,983)	(6,878)	—	(85,861)
Acquisition of leasehold interests	—	(312,207)	—	—	(312,207)
Acquisition of mineral interests	—	—	—	—	—
Purchase of other property and equipment	—	(595)	—	—	(595)
Intercompany transfers	(204,544)	197,619	—	6,925	—
Other investing activities	—	(521)	—	—	(521)
Net cash used in investing activities	(204,544)	(194,687)	(6,878)	6,925	(399,184)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	127,000	—	—	127,000
Proceeds from public offerings	208,644	—	—	—	208,644
Other financing activities	1,967	(9)	(28)	(97)	1,833
Net cash provided by (used in) financing activities	210,611	126,991	(28)	(97)	337,477
Net increase (decrease) in cash and cash equivalents	9,390	(108)	(363)	840	9,759
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$9,916	$14,159	$399	$840	$25,314

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, 2014. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Part II. Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are 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 77% oil, 13% natural gas liquids and 10% natural gas for the three months ended March 31, 2015, and was approximately 79% oil, 11% natural gas liquids and 10% natural gas for the three months ended March 31, 2014. On March 31, 2015, our net acreage position in the Permian Basin was approximately 77,866 net acres.

Recent Developments

Common stock transactions

In January 2015, we completed an underwritten public offering of 1,750,000 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and we received net proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Recent and pending acquisitions

Since January 1, 2015, we have acquired or have entered into definitive purchase agreements to acquire from unrelated third party sellers an aggregate of approximately 15,940 gross (11,948 net) acres in the Midland Basin, primarily in northwest Howard County, in the Permian Basin, for an aggregate purchase price of approximately $437.8 million, subject to certain adjustments. During April 2015, based on information reported by the sellers, net production attributable to this acreage is estimated to have been approximately 2,500 BOE/d (on a three-stream basis) (approximately 54% oil) from 117 gross producing vertical wells and three horizontal wells. Based on our evaluation and interpretation of reserve and production information provided by the sellers, as well as our analysis of available geologic and other data, we estimate net proved reserves as of the effective date for the for the acquisition of the applicable assets were approximately 4,347 MBOE. Our estimate of proved reserves has not been reviewed by our independent reserve engineers, and we may revise our estimates following ownership and operation of these properties. Approximately 83% of this acreage is held by production. We believe the acreage is prospective for horizontal drilling in the Lower Spraberry, Wolfcamp A and Wolfcamp B horizons, and have identified an aggregate of approximately 232 net potential horizontal drilling locations in these horizons based on 660 foot spacing between wells. We currently estimate that approximately 42% of the potential horizontal locations will have approximately 10,000 foot laterals, which can provide higher rates of return and capital efficiency than shorter laterals. The average lateral length for these potential horizontal locations is estimated to be approximately 8,357 feet. We also believe that additional development potential may exist in the Middle Spraberry horizon. Salt water disposal infrastructure is already in place on the acreage in Northwest Howard County, and the acquisitions include 3-D seismic data that can be used to geosteer the drilling of horizontal wells. We have offered an average approximate 1.5% overriding royalty interest in certain of the acreage subject to these acquisitions to Viper for $33.7 million. This offer is subject to the approval of the conflicts committee of Viper's general partner and our completion of the acquisitions, and there can be no assurance that this transaction will be completed on these terms or at all. We intend to finance the acquisitions, subject to market conditions and other factors, primarily with proceeds from one or more capital market transactions, which may include debt or equity offerings. We anticipate that we will become the operator of approximately 93% of this net acreage following the completion of these acquisitions, all of which are expected to have been completed by the end of June 2015. However, substantially all of the transactions remain subject to completion of due diligence and satisfaction of other closing conditions. There can be no assurance that we will acquire all or any portion of the acreage described above.

Operating Results Overview

During the three months ended March 31, 2015, our average daily production was approximately 30,636 BOE/d, consisting of 23,687 Bbls/d of oil, 17,765 Mcf/d of natural gas and 3,988 Bbls/d of natural gas liquids, an increase of 17,084 BOE/d, or 126%, from average daily production of 13,552 BOE/d for the three months ended March 31, 2014, consisting of 10,663 Bbls/d of oil, 7,871 Mcf/d of natural gas and 1,578 Bbls/d of natural gas liquids.

During the three months ended March 31, 2015, we drilled 15 gross (13 net) horizontal wells and two gross (one net) vertical wells and did not participate in the drilling of any non-operated wells in the Permian Basin. In April 2015, we completed our first Lower Spraberry test well on the acreage we acquired in Southwest Martin County in 2014. The Kimberly 714LS has a 7,472 foot lateral and was completed with 32 frac stages. This well is in initial flowback and is still cleaning up. In April 2015, we drilled an approximate 8,200 foot lateral (measured depth of approximately 18,000 feet) in Southwest Martin County in 12 days. In February 2015, we drilled a two-well pad in Midland County with an average lateral length of approximately 10,000 feet (average measured depth of approximately 19,000 feet) in 31 days from the spudding of the first well to total depth of the second well.

As commodity prices have strengthened during the second quarter of 2015 and we have received cost concessions from our service providers of up to 20% to 30% as compared to their peak pricing during 2014, we no longer plan to defer completions and, instead, intend to add a second dedicated completion crew in June to work on our backlog of drilled but uncompleted horizontal wells. Further, if cost concessions hold and commodity prices remain stable or strengthen, we expect to increase our horizontal rig count from three currently to five later this year and, potentially, to seven or eight in 2016. We now intend to complete 55 to 65 gross horizontal wells during 2015, an increase from our prior estimated range of 50 to 60 gross wells. In light of our continuing operational efficiencies and the cost concessions we have seen, we expect to complete these additional wells without an increase in our estimated $400.0 million to $450.0 million of capital expenditures in 2015. In addition, we are projecting that at $60/bbl for WTI, our leading edge cost savings and our efficiency gains will allow us to generate estimated project rates of return comparable to those generated when WTI was $75/bbl, but involved higher drilling and completion costs.

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 March 31, 2015, our revenues were derived 92% from oil sales, 4% from natural gas liquids sales and 4% from natural gas sales. For the three months ended March 31, 2014, our revenues were derived 92% from oil sales, 5% from natural gas liquids sales and 3% 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 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On March 31, 2015, the West Texas Intermediate posted price for crude oil was $47.72 per Bbl and the Henry Hub spot market price of natural gas was $2.65 per MMBtu.

The industry has recently observed a decline in oil prices from over $105.00 per Bbl in June 2014 to below $50.00 per Bbl during the majority of the three months ended March 31, 2015, combined with increasing service costs. While we entered 2015 running five horizontal rigs and one vertical rig, we released two horizontal rigs and the one vertical rig in February 2015 and continue with three horizontal rigs, two of which are operating in Spanish Trail. Our decision to reduce our rig count, rather than increase it as previously contemplated, is 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 March 31,	
	2015	2014
	(in thousands, except Bbl, Mcf and BOE amounts)	
Revenues		
Oil and natural gas revenues	$ 101,401	$ 98,004
Operating Expenses		
Lease operating expense	22,456	7,915
Production and ad valorem taxes	8,395	5,842
Gathering and transportation expense	1,030	582
Depreciation, depletion and amortization	59,677	30,973
General and administrative	8,236	4,557
Asset retirement obligation accretion expense	170	72
Total expenses	99,964	49,941
Income from operations	1,437	48,063
Net interest expense	(10,497)	(6,505)
Other income	515	30
Other expense	—	—
Gain (loss) on derivative instruments, net	18,354	(4,398)
Loss from equity investment	—	—
Total other income (expense), net	8,372	(10,873)
Income before income taxes	9,809	37,190
Income tax provision	3,370	13,601
Net income (loss)	6,439	23,589
Less: Net income attributable to noncontrolling interest	590	—
Net income (loss) attributable to Diamondback Energy, Inc.	$ 5,849	$ 23,589
Production Data:		
Oil (Bbls)	2,131,829	959,631
Natural gas (Mcf)	1,598,810	708,419
Natural gas liquids (Bbls)	358,924	142,023
Combined volumes (BOE)	2,757,221	1,219,724
Daily combined volumes (BOE/d)	30,636	13,552
Average Prices[1]:		
Oil (per Bbl)	$ 43.59	$ 93.53
Natural gas (per Mcf)	2.72	4.71
Natural gas liquids (per Bbl)	11.53	34.58
Combined (per BOE)	36.78	80.35
Average Costs (per BOE)		
Lease operating expense	$ 8.14	$ 6.49
Gathering and transportation expense	0.37	0.48
Production and ad valorem taxes	3.04	4.79
Production and ad valorem taxes as a % of sales	8.3 %	6.0 %
Depreciation, depletion, and amortization	21.64	25.39
General and administrative[2]	2.99	3.74

Interest expense	3.81	5.33

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(1) After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $64.01 and $52.57, respectively, during the three months ended March 31, 2015 and $92.43 and $79.48, respectively, during the three months ended March 31, 2014.

(2) General and administrative includes non-cash stock based compensation, net of capitalized amounts, of $4,924 and $2,190 for the three months ended March 31, 2015 and 2014, respectively. Excluding stock based compensation from the above metric results in general and administrative cost per BOE of $1.20 and $1.94 for the three months ended March 31, 2015 and 2014, respectively.

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Comparison of the Three Months Ended March 31, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $3.4 million, or 3%, to $101.4 million for the three months ended March 31, 2015 from $98.0 million for the three months ended March 31, 2014. 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 17,084 BOE/d to 30,636 BOE/d during the three months ended March 31, 2015 from 13,552 BOE/d during the three months ended March 31, 2014. The total increase in revenue of approximately $3.4 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014, substantially offset by lower average sales prices. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 1,172,198 Bbls of oil, 216,901 Bbls of natural gas liquids and 890,391 Mcf of natural gas for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014. The net dollar effect of the decreases in prices of approximately $117.9 million (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 $121.3 million (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	$(49.94)	2,131,829	$(106,472)
Natural gas liquids	$(23.05)	358,924	$(8,275)
Natural gas	$(1.99)	1,598,810	$(3,182)
Total revenues due to change in price			$(117,929)

	Change in production volumes[(1)]	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	1,172,198	$93.53	$109,635
Natural gas liquids	216,901	$34.58	$7,500
Natural gas	890,391	$4.71	$4,191
Total revenues due to change in production volumes			$121,326
Total change in revenues			$3,397

(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 $22.5 million ($8.14 per BOE) for the three months ended March 31, 2015, an increase of $14.5 million, or 184%, from $7.9 million ($6.49 per BOE) for the three months ended March 31, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 152 additional producing wells, for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014. 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.

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Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $8.4 million for the three months ended March 31, 2015 from $5.8 million for the three months ended March 31, 2014. 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 March 31, 2015, our production taxes per BOE decreased by $1.75 as compared to the three months ended March 31, 2014, 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 $28.7 million, or 93%, from $31.0 million for the three months ended March 31, 2014 to $59.7 million for the three months ended March 31, 2015.

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

	Three Months Ended March 31,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$59,255	$30,724
Depreciation of other property and equipment	422	249
DD&A	$59,677	$30,973
Oil and natural gas properties DD&A per BOE	$21.49	$25.19
Total DD&A per BOE	$21.64	$25.39

The increases in depletion of proved oil and natural gas properties of $28.5 million for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014 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 $3.7 million from $4.6 million for the three months ended March 31, 2014 to $8.2 million for the three months ended March 31, 2015. The increase was due to increases in stock based compensation and salaries and benefits expense.

Net Interest Expense. Net interest expense for the three months ended March 31, 2015 was $10.5 million as compared to $6.5 million for the three months ended March 31, 2014, an increase of $4.0 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during the three months ended March 31, 2015 as compared to the three months ended March 31, 2014.

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 combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended March 31, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $43.6 million and a cash loss on settlement of derivative instruments of $1.1 million, respectively. For the three months ended March 31, 2015 and 2014, we had a negative change in the fair value of open derivative instruments of $25.2 million and $3.3 million, respectively.

Income Tax Expense. We recorded income tax expense of $3.4 million for the three months ended March 31, 2015 as compared to $13.6 million for the three months ended March 31, 2014. Our effective tax rate was 34.4% for the three months ended March 31, 2015 as compared to 36.6% for the three months ended March 31, 2014.

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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 three months ended March 31, 2015 and 2014 are presented below:

	Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Net cash provided by operating activities	$99,143	$71,466
Net cash used in investing activities	(153,555)	(399,184)
Net cash provided by financing activities	$55,872	$337,477
Net change in cash	$1,460	$9,759

Operating Activities

Net cash provided by operating activities was $99.1 million for the three months ended March 31, 2015 as compared to $71.5 million for the three months ended March 31, 2014. The increase in operating cash flows is primarily the result of the increase in our oil and natural gas revenues due to a 126.1% increase in our net BOE production, partially offset by a 54.2% decrease in our net realized sales prices.

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 $153.6 million and $399.2 million during the three months ended March 31, 2015 and 2014, respectively.

During the three months ended March 31, 2015, we spent $151.4 million on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 15 gross (13 net) horizontal wells and two gross (one net) vertical wells. We spent an additional $2.0 million on leasehold costs, $0.2 million for the purchase of other property and equipment.

During the three months ended March 31, 2014, we spent $86.4 million on capital expenditures in conjunction with our drilling program in which we drilled 29 gross (24 net) wells and participated in the drilling of an additional one gross non-operated wells. We spent an additional $312.2 million on leasehold costs and $0.6 million for the purchase of other property and equipment. In February 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.

Our investing activities for the three months ended March 31, 2015 and 2014 are summarized in the following table:

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	Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Drilling, completion and infrastructure	$(151,397)	$(86,393)
Acquisition of leasehold interests	(2,000)	(312,207)
Acquisition of Gulfport properties	—	—
Acquisition of mineral interests	—	—
Purchase of other property and equipment	(158)	(595)
Proceeds from sale of property and equipment	—	11
Cost method investment	—	—
Settlement of non-hedge derivative instruments	—	—
Receipt on derivative margins	—	—
Net cash used in investing activities	$(153,555)	$(399,184)

Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2015 and 2014 was $55.9 million and $337.5 million, respectively. During the three months ended March 31, 2015, the amount provided by financing activities was primarily attributable to the net proceeds from our January 2015 equity offering of $119.4 million partially offset by the repayment, net of borrowings of $61.9 million under our credit facility. The 2014 amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering and borrowings of $127.0 million under our credit facility.

Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014 and November 13, 2014, 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 $2.0 billion, 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 May 1st and November 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2015, the borrowing base was set at $750.0 million, although we elected a commitment amount of $500.0 million. In connection with our Spring 2015 redetermination, the agent lender under the credit agreement has recommended that our borrowing base be set at $725.0 million. This adjustment is subject to the approval of our other lenders. Regardless of such adjustment, we currently intend to continue our election of a commitment amount of $500.0 million. As of March 31, 2015, we had outstanding borrowings of $161.6 million, which bore a weighted-average interest rate of 1.92%, and $338.4 million available for future borrowings under this facility. As of March 31, 2015, the credit agreement 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 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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. 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.

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 March 31, 2015, we had $450 million of senior notes outstanding.

As of March 31, 2015, 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, Viper 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 Viper’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, Viper may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2015, the borrowing base was set at $110.0 million and Viper had no outstanding borrowings. In connection with Viper’s Spring 2015 redetermination, the agent lender under the credit agreement has recommended that Viper’s borrowing base be increased to $175.0 million. This increase is subject to the approval of the other lenders.

The outstanding borrowings under Viper's credit agreement bear interest at a rate elected by Viper that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Viper 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 Viper 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 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the

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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 Viper's revolving credit facility upon the occurrence and during the continuance of any event of default. The Viper 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 2015 capital budget for drilling and infrastructure of $400.0 million to $450.0 million. We estimate that, of these expenditures, approximately:

- $285.0 million to $315.0 million will be spent on drilling and completing 50 to 60 gross (43 to 52 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;
- $20.0 million to $30.0 million will be spent on infrastructure;
- $20.0 million to $30.0 million will be spent on non-operated activity and other expenditures; and
- an estimated $75.0 million for expenditures related to 2014 activity (net of expenditures from 2015 expected to be carried into 2016).

During the three months ended March 31, 2015, our aggregate capital expenditures for drilling and infrastructure were $151.4 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the three months ended March 31, 2015, we spent approximately $2.0 million on acquisitions of leasehold interests. For information regarding our recently completed and pending acquisitions, see "—Recent Developments—Recent and pending acquisitions."

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 2015, 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 2015. 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 2015 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.

Contractual Obligations

Except as discussed in Note 14 of the Notes to the Consolidated Financial Statements of this Form 10-Q there were no material changes to our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

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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, 2014

Off-balance Sheet Arrangements

We currently have no off-balance sheet arrangements as of March 31, 2015. Please read Note 15 included in Notes to the Combined Consolidated Financial Statements set forth in Part I, Item 1 of this Form 10–Q, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

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 March 31, 2015, we had a net asset derivative position of $92.3 million, related to our price swap derivatives, as compared to a net asset derivative position of $0.4 million as of December 31, 2014 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of March 31, 2015, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to $76.5 million, a decrease of $15.8 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $108.2 million, an increase of $15.8 million. 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.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $44.6 million at March 31, 2015) and receivables from the sale of our oil and natural gas production (approximately $38.6 million at March 31, 2015).

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 three months ended March 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (68%) and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%) and Enterprise Crude Oil LLC (16%). 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 March 31, 2015, we had one customer that represented approximately 44% of our total joint operations receivables. At December 31, 2014, we had one customer that represented approximately 61% of our total joint operations receivables.

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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 under our credit facility was 1.92% at March 31, 2015. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $1.6 million based on the $161.6 million outstanding in the aggregate under our revolving credit facility on March 31, 2015.

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 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 March 31, 2015, 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 March 31, 2015, 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 March 31, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II

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, 2014. 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, 2014.

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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).
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 among Diamondback Energy, Inc., the subsidiary guarantors party thereto and Wells Fargo, National Association, 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	Second Supplemental Indenture, dated as of October 8, 2014, by and among Diamondback Energy, Inc., White Fang Energy LLC, as subsidiary guarantor, other subsidiary guarantors party

	thereo and Wells Fargo, National Association, as trustee.
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.

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Exhibit Number	Description
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.

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* Filed herewith.

** The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Annual Report on Form 10-K 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.

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.

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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: May 6, 2015

/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)