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

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# FORM 10-Q

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

**FOR THE QUARTERLY PERIOD ENDED September 30, 2016**

**OR**

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

**Commission File Number 001-35700**

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

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| | |
|---|---|
| **Delaware** | **45-4502447** |
| **(State or Other Jurisdiction of Incorporation or Organization)** | **(IRS Employer Identification Number)** |
| **500 West Texas, Suite 1200<br>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 ☒ 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 ☒ 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 | ☒ | 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 ☒

As of November 3, 2016, 78,066,147 shares of the registrant’s common stock were outstanding.

DIAMONDBACK ENERGY, INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2016

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**GLOSSARY OF OIL AND NATURAL GAS TERMS**

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

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

| | |
|---|---|
| Reservoir | A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs. |
| Royalty interest | An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development. |
| Spacing | The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies. |
| Working interest | An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations. |

## GLOSSARY OF CERTAIN OTHER TERMS

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

| | |
|---|---|
| 2012 Plan | The Company’s 2012 Equity Incentive Plan. |
| Company | Diamondback Energy, Inc., a Delaware corporation. |
| Exchange Act | The Securities Exchange Act of 1934, as amended. |
| GAAP | Accounting principles generally accepted in the United States. |
| General Partner | Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership. |
| Indenture | The indenture relating to the Senior Notes, dated as of September 18, 2013, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented. |
| NYMEX | New York Mercantile Exchange. |
| Partnership | Viper Energy Partners LP, a Delaware limited partnership. |
| Partnership agreement | The first amended and restated agreement of limited partnership, dated June 23, 2014, entered into by the General Partner and Diamondback in connection with the closing of the Viper Offering. |
| SEC | United States Securities and Exchange Commission. |
| Securities Act | The Securities Act of 1933, as amended. |
| Senior Notes | The Company’s 7.625% senior unsecured notes due 2021 in the aggregate principal amount of $450 million. |
| Viper LTIP | Viper Energy Partners LP Long Term Incentive Plan. |
| Viper Offering | The Partnerships’ initial public offering. |
| Wells Fargo | Wells Fargo Bank, National Association. |

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this report 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, 2015 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;
- acquisitions, including our recently announced pending acquisition in the Southern Delaware Basin;
- 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 or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities laws. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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

| | | September 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| | | (In thousands, except par values and share data) | | |
| **Assets** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ | 167,269 | $ | 20,115 |
| Restricted cash | | 500 | | 500 |
| Accounts receivable: | | | | |
| Joint interest and other | | 33,030 | | 41,309 |
| Oil and natural gas sales | | 52,471 | | 36,004 |
| Related party | | 13 | | 1,591 |
| Inventories | | 1,969 | | 1,728 |
| Derivative instruments | | — | | 4,623 |
| Prepaid expenses and other | | 3,018 | | 2,875 |
| Total current assets | | 258,270 | | 108,745 |
| Property and equipment: | | | | |
| Oil and natural gas properties, full cost method of accounting ($1,702,426 and $1,106,816 excluded from amortization at September 30, 2016 and December 31, 2015, respectively) | | 4,942,193 | | 3,955,373 |
| Pipeline and gas gathering assets | | 8,362 | | 7,174 |
| Other property and equipment | | 58,205 | | 48,621 |
| Accumulated depletion, depreciation, amortization and impairment | | (1,784,780) | | (1,413,543) |
| Net property and equipment | | 3,223,980 | | 2,597,625 |
| Other assets | | 43,430 | | 44,349 |
| Total assets | $ | 3,525,680 | $ | 2,750,719 |
| **Liabilities and Stockholders' Equity** | | | | |
| Current liabilities: | | | | |
| Accounts payable-trade | $ | 38,834 | $ | 20,008 |
| Accounts payable-related party | | 2 | | 217 |
| Accrued capital expenditures | | 47,807 | | 59,937 |
| Other accrued liabilities | | 64,393 | | 44,293 |
| Revenues and royalties payable | | 17,561 | | 16,966 |
| Derivative instruments | | 6,428 | | — |
| Total current liabilities | | 175,025 | | 141,421 |
| Long-term debt | | 497,813 | | 487,807 |
| Derivative instruments | | 1,807 | | — |
| Asset retirement obligations | | 15,740 | | 12,518 |
| Total liabilities | | 690,385 | | 641,746 |
| Commitments and contingencies (Note 15) | | | | |
| Stockholders' equity: | | | | |
| Common stock, $0.01 par value, 100,000,000 shares authorized, 78,066,147 issued and outstanding at September 30, 2016; 66,797,041 issued and outstanding at December 31, 2015 | | 781 | | 668 |
| Additional paid-in capital | | 3,059,080 | | 2,229,664 |
| Accumulated deficit | | (544,992) | | (354,360) |
| Total Diamondback Energy, Inc. stockholders' equity | | 2,514,869 | | 1,875,972 |
| Non-controlling interest | | 320,426 | | 233,001 |
| Total equity | | 2,835,295 | | 2,108,973 |
| Total liabilities and equity | $ | 3,525,680 | $ | 2,750,719 |

See accompanying notes to combined consolidated financial statements.

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (In thousands, except per share amounts) | | | |
| **Revenues:** | | | | |
| Oil sales | $ 126,353 | $ 101,307 | $ 306,698 | $ 301,850 |
| Natural gas sales | 6,334 | 5,673 | 14,465 | 14,431 |
| Natural gas liquid sales | 9,444 | 4,966 | 20,932 | 16,129 |
| Total revenues | 142,131 | 111,946 | 342,095 | 332,410 |
| **Costs and expenses:** | | | | |
| Lease operating expenses | 22,180 | 22,189 | 59,080 | 65,117 |
| Production and ad valorem taxes | 9,123 | 8,966 | 25,244 | 25,036 |
| Gathering and transportation | 2,843 | 1,688 | 8,064 | 4,343 |
| Depreciation, depletion and amortization | 44,746 | 52,375 | 126,686 | 169,148 |
| Impairment of oil and natural gas properties | 46,368 | 273,737 | 245,536 | 597,188 |
| General and administrative expenses (including non-cash equity-based compensation, net of capitalized amounts, of $6,265 and $4,402 for the three months ended September 30, 2016 and 2015, respectively, and $20,643 and $13,659 for the nine months ended September 30, 2016 and 2015, respectively) | 9,908 | 7,526 | 32,411 | 23,446 |
| Asset retirement obligation accretion expense | 270 | 238 | 770 | 588 |
| Total costs and expenses | 135,438 | 366,719 | 497,791 | 884,866 |
| **Income (loss) from operations** | 6,693 | (254,773) | (155,696) | (552,456) |
| **Other income (expense):** | | | | |
| Interest income (expense) | (10,234) | (10,633) | (30,266) | (31,404) |
| Other income | 907 | 300 | 1,647 | 1,248 |
| Gain (loss) on derivative instruments, net | 2,034 | 27,603 | (8,665) | 26,834 |
| Total other expense, net | (7,293) | 17,270 | (37,284) | (3,322) |
| **Loss before income taxes** | (600) | (237,503) | (192,980) | (555,778) |
| Provision for (benefit from) income taxes | — | (81,461) | 368 | (194,823) |
| **Net loss** | (600) | (156,042) | (193,348) | (360,955) |
| Net income (loss) attributable to non-controlling interest | 1,630 | 739 | (2,716) | 2,264 |
| **Net loss attributable to Diamondback Energy, Inc.** | $ (2,230) | $ (156,781) | $ (190,632) | $ (363,219) |
| **Earnings per common share:** | | | | |
| Basic | $ (0.03) | $ (2.40) | $ (2.60) | $ (5.88) |
| Diluted | $ (0.03) | $ (2.40) | $ (2.60) | $ (5.88) |
| **Weighted average common shares outstanding:** | | | | |
| Basic | 77,167 | 65,251 | 73,318 | 61,727 |
| Diluted | 77,167 | 65,251 | 73,318 | 61,727 |

See accompanying notes to combined consolidated financial statements.

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

| | Common Stock | | Additional Paid-in Capital | Retained Earnings (Accumulated Deficit) | Non-Controlling Interest | Total |
|---|---|---|---|---|---|---|
| | Shares | Amount | | | | |
| | (In thousands) | | | | | |
| Balance December 31, 2014 | 56,888 | $ 569 | $ 1,554,174 | $ 196,268 | $ 234,202 | $ 1,985,213 |
| Unit-based compensation | | — | — | — | 2,956 | 2,956 |
| Stock-based compensation | | — | 15,827 | — | — | 15,827 |
| Distribution to non-controlling interest | | — | — | — | (6,113) | (6,113) |
| Common shares issued in public offering, net of offering costs | 9,488 | 94 | 649,979 | — | — | 650,073 |
| Exercise of stock options and vesting of restricted stock units | 281 | 4 | 2,715 | — | — | 2,719 |
| Net income (loss) | | — | — | (363,219) | 2,264 | (360,955) |
| Balance September 30, 2015 | 66,656 | $ 667 | $ 2,222,695 | $ (166,951) | $ 233,309 | $ 2,289,720 |
| | | | | | | |
| Balance December 31, 2015 | 66,797 | $ 668 | $ 2,229,664 | $ (354,360) | $ 233,001 | $ 2,108,973 |
| Net proceeds from issuance of common units - Viper Energy Partners LP | | — | — | — | 93,564 | 93,564 |
| Unit-based compensation | | — | — | — | 2,974 | 2,974 |
| Stock-based compensation | | — | 23,193 | — | — | 23,193 |
| Distribution to non-controlling interest | | — | — | — | (6,397) | (6,397) |
| Common shares issued in public offering, net of offering costs | 10,925 | 109 | 805,728 | — | — | 805,837 |
| Exercise of stock options and vesting of restricted stock units | 344 | 4 | 495 | — | — | 499 |
| Net loss | | — | — | (190,632) | (2,716) | (193,348) |
| Balance September 30, 2016 | 78,066 | $ 781 | $ 3,059,080 | $ (544,992) | $ 320,426 | $ 2,835,295 |

See accompanying notes to combined consolidated financial statements.

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2016** | **2015** |
| | **(In thousands)** | |
| Cash flows from operating activities: | | |
| Net loss | $ (193,348) | $ (360,955) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Benefit from deferred income taxes | — | (194,790) |
| Impairment of oil and natural gas properties | 245,536 | 597,188 |
| Asset retirement obligation accretion expense | 770 | 588 |
| Depreciation, depletion, and amortization | 126,686 | 169,148 |
| Amortization of debt issuance costs | 2,023 | 1,918 |
| Change in fair value of derivative instruments | 12,858 | 77,532 |
| Income from equity investment | (65) | — |
| Equity-based compensation expense | 20,643 | 13,659 |
| (Gain) loss on sale of assets, net | 37 | (91) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (7,600) | 13,112 |
| Accounts receivable-related party | 1,578 | — |
| Inventories | (241) | 225 |
| Prepaid expenses and other | (2,064) | 569 |
| Accounts payable and accrued liabilities | 10,590 | 22,756 |
| Accounts payable and accrued liabilities-related party | (216) | — |
| Accrued interest | 8,564 | 8,324 |
| Revenues and royalties payable | 595 | (9,579) |
| Net cash provided by operating activities | 226,346 | 339,604 |
| Cash flows from investing activities: | | |
| Additions to oil and natural gas properties | (241,609) | (326,441) |
| Additions to oil and natural gas properties-related party | (637) | (26) |
| Acquisition of royalty interests | (137,782) | (32,291) |
| Acquisition of leasehold interests | (591,785) | (425,507) |
| Additions to pipeline and gas gathering assets | (1,188) | (2) |
| Purchase of other property and equipment | (9,805) | (992) |
| Proceeds from sale of assets | 1,566 | 97 |
| Equity investments | (800) | (2,702) |
| Net cash used in investing activities | (982,040) | (787,864) |
| Cash flows from financing activities: | | |
| Proceeds from borrowings under credit facility | 98,000 | 392,501 |
| Repayment under credit facility | (89,000) | (577,001) |
| Debt issuance costs | (128) | (303) |
| Public offering costs | (800) | (586) |
| Proceeds from public offerings | 900,675 | 650,688 |
| Proceeds from exercise of stock options | 498 | 2,718 |
| Distribution to non-controlling interest | (6,397) | (6,113) |
| Net cash provided by financing activities | 902,848 | 461,904 |
| Net increase in cash and cash equivalents | 147,154 | 13,644 |
| Cash and cash equivalents at beginning of period | 20,115 | 30,183 |
| Cash and cash equivalents at end of period | $ 167,269 | $ 43,827 |

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2016** | **2015** |
| | **(In thousands)** | |
| **Supplemental disclosure of cash flow information:** | | |
| Interest paid, net of capitalized interest | $ 19,845 | $ 21,117 |
| **Supplemental disclosure of non-cash transactions:** | | |
| Change in accrued capital expenditures | $ (12,130) | $ (70,579) |
| Capitalized stock-based compensation | $ 5,525 | $ 5,125 |

See accompanying notes to combined consolidated financial statements.

## 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.

The wholly-owned subsidiaries of Diamondback, as of September 30, 2016, 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 (the "Partnership"), and the Partnership's wholly-owned subsidiary Viper Energy Partners LLC, a Delaware limited liability company.

***Basis of Presentation***

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

The Partnership is consolidated in the financial statements of the Company. As of September 30, 2016, the Company owned approximately 83% 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 SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been omitted pursuant to such rules and regulations, although the 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, 2015, 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 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, equity-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

***New Accounting Pronouncements***

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, “Interest–Imputation of Interest”. This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) 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. This update is effective for financial statements issued for fiscal years beginning after December 15, 2015. The Company retrospectively adopted this new standard effective January 1, 2016. Adoption of this standard only affects the presentation of the Company’s consolidated balance sheets and did not have a material impact on its consolidated financial statements.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, “Financial Instruments–Overall”. This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. This update will be effective for public entities for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. Entities should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. While this update will not have a direct impact on the Company, the Partnership will be required to mark its cost method investment to fair value with the adoption of this update.

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, “Leases”. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Company is currently evaluating the impact that the adoption of this update will have on the Company’s financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-08, “Revenue from Contracts with Customers - Principal versus Agent Considerations (Reporting Revenue Gross versus Net)”. Under this update, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This update will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. This update allows for either full retrospective adoption, meaning this update is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning this update is applied only to the most current period presented. The Company is currently evaluating the impact, if any, that the adoption of this update will have on the Company’s financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-09, "Compensation - Stock Compensation". This update applies to all entities that issue equity-based payment awards to their employees. Under this update, there were several areas that were simplified including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years with early adoption permitted. The Company is currently evaluating the impact that the adoption of this update will have on the Company's financial position, results of operations and liquidity.

In April 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-10, “Revenue from Contracts with Customers - Identifying Performance Obligations and Licensing”. This update clarifies two principles of Accounting Standards Codification Topic 606: identifying performance obligations and the licensing implementation guidance. This standard has the same effective date as Accounting Standards Update 2016-08, the revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Company's financial position, results of operations and liquidity.

In May 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-12, “Revenue from Contracts with Customers - Narrow-Scope Improvements and Practical Expedients”. This update applies only to the following areas from Accounting Standards Codification Topic 606: assessing the collectability criterion and accounting for contracts that do not meet the criteria for step 1, presentation of sales taxes and other similar taxes collected from customers, noncash consideration, contract modification at transition, completed contracts at transition and technical correction. This standard has the same effective date as Accounting Standards Update 2016-08, the revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Company's financial position, results of operations and liquidity.

In August 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-15, “Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments”. This update apples to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years with early adoption permitted. This update should be applied using the retrospective transition method. Adoption of this standard will only affect the presentation of the Company’s cash flows and will not have a material impact on its consolidated financial statements.

## 3. ACQUISITIONS

### *2016 Activity*

On September 1, 2016, the Company acquired from an unrelated third party leasehold interests and related assets in the Southern Delaware Basin for an aggregate purchase price of $560.0 million, subject to certain adjustments. This transaction included approximately 38,765 gross (19,180 net) acres primarily in Reeves and Ward counties, 19 gross producing vertical wells, 11 gross producing horizontal wells, saltwater disposal and gathering infrastructure and other related assets. The Company financed this acquisition with net proceeds from the July 2016 equity offering discussed in Note 9 and cash on hand.

### *2015 Activity*

During the nine months ended September 30, 2015, the Company completed acquisitions from unrelated third parties of an aggregate of approximately 16,034 gross (12,396 net) acres in the Midland Basin, primarily in northwest Howard County, for an aggregate purchase price of approximately $426.1 million. 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 May 2015 equity offering discussed in Note 9 and borrowings under the Company’s revolving credit facility discussed in Note 8.

On July 9, 2015, the Company completed the sale of an approximate average 1.5% overriding royalty interest in certain of its acreage primarily located in Howard County, Texas to the Partnership for $31.1 million. The Partnership primarily funded this acquisition with borrowings under its revolving credit facility discussed in Note 8.

## 4. VIPER ENERGY PARTNERS LP

The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by Diamondback on February 27, 2014, to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of September 30, 2016, the Company owned approximately 83% of the common units of 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, dated June 23, 2014 (the “Partnership Agreement”). 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 with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership’s results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership’s benefit, even though Diamondback had no cash tax expense for that period.

***Other Agreements***

See Note 11—Related Party Transactions for information regarding the advisory services agreement the Partnership and the General Partner entered into with Wexford Capital LP (“Wexford”).

The Partnership has entered into a secured revolving credit facility with 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:

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Oil and natural gas properties: | | |
| Subject to depletion | $ 3,239,767 | $ 2,848,557 |
| Not subject to depletion-acquisition costs | | |
| Incurred in 2016 | 671,815 | — |
| Incurred in 2015 | 420,039 | 433,769 |
| Incurred in 2014 | 487,958 | 543,399 |
| Incurred in 2013 | 61,871 | 68,351 |
| Incurred in 2012 | 60,743 | 61,297 |
| Total not subject to depletion | 1,702,426 | 1,106,816 |
| Gross oil and natural gas properties | 4,942,193 | 3,955,373 |
| Accumulated depletion | (636,771) | (512,144) |
| Accumulated impairment | (1,143,498) | (897,962) |
| Oil and natural gas properties, net | 3,161,924 | 2,545,267 |
| Pipeline and gas gathering assets | 8,362 | 7,174 |
| Other property and equipment | 58,205 | 48,621 |
| Accumulated depreciation | (4,511) | (3,437) |
| Property and equipment, net of accumulated depreciation, depletion, amortization and impairment | $ 3,223,980 | $ 2,597,625 |

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. 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 $3.9 million and $4.0 million for the three months ended September 30, 2016 and 2015, respectively, and $13.0 million and $12.1 million for the nine months ended September 30, 2016 and 2015, 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. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

As a result of the decline in prices, the Company recorded non-cash impairments for the nine months ended September 30, 2016 and 2015 of $245.5 million and $597.2 million, respectively, which are included in accumulated depletion. The impairment charge affected the Company's reported net income but did not reduce its cash flow. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

## 6. ASSET RETIREMENT OBLIGATIONS

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2016** | **2015** |
| | **(in thousands)** | |
| Asset retirement obligation, beginning of period | $ 12,711 | $ 8,486 |
| Additional liability incurred | 406 | 448 |
| Liabilities acquired | 3,022 | 3,123 |
| Liabilities settled | (402) | (4) |
| Accretion expense | 770 | 588 |
| Revisions in estimated liabilities | 25 | 60 |
| Asset retirement obligation, end of period | 16,532 | 12,701 |
| Less current portion | 792 | 39 |
| Asset retirement obligations - long-term | $ 15,740 | $ 12,662 |

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 25% interest in HMW Fluid Management LLC, which 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. During the nine months ended September 30, 2016, the Company invested $0.8 million in this entity bringing its total investment to $4.1 million at September 30, 2016. 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:

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| 7.625 % Senior Notes due 2021 | $ 450,000 | $ 450,000 |
| Unamortized debt issuance | (6,687) | (7,693) |
| Revolving credit facility | — | 11,000 |
| Partnership revolving credit facility | 54,500 | 34,500 |
| Total long-term debt | $ 497,813 | $ 487,807 |

***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 “2021 Senior Notes”). The 2021 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 2021 Senior Notes, was released as a guarantor under the indenture. As of September 30, 2016, the 2021 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 2021 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 2021 Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association (“Wells Fargo”), 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 2021 Senior Notes may have the right to require the Company to repurchase their 2021 Senior Notes.

The Company will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. See Note 16. Subsequent Events–Tender Offer and Redemption–Existing 2021 Senior Notes.

***The Company’s Credit Facility***

On June 9, 2014, Diamondback O&G LLC, as borrower, entered into a first amendment and on November 13, 2014, Diamondback O&G LLC entered into a second amendment to the second amended and restated credit agreement, dated November 1, 2013 (the “credit agreement”). The first amendment modified certain provisions of the credit agreement to, among other things, allow one or more of the Company’s subsidiaries to be designated as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Partnership, the General Partner and Viper Energy Partners LLC were designated as unrestricted subsidiaries under the credit agreement. As of September 30, 2016, the credit agreement was 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 Diamondback O&G LLC, the Company and the other 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 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 September 30, 2016, the borrowing base was set at $700.0 million, of which the Company had elected a commitment amount of $500.0 million, and the Company had no outstanding borrowings.

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 0.50% 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. 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 repaid (a) to the extent that 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 $750.0 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of September 30, 2016, the Company had $450.0 million in aggregate principal amount of senior unsecured notes outstanding. See Note 16. Subsequent Events–Tender Offer and Redemption–Existing 2021 Senior Notes.

As of September 30, 2016 and December 31, 2015, 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.

***The Partnership's Credit Agreement***

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, as amended, 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 is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the

Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2016, the borrowing base was set at $175.0 million. On August 5, 2016, the Partnership repaid $78.0 million of its outstanding borrowings with a portion of the proceeds from its August 2016 public offering of common units and, as of September 30, 2016, the Partnership had $54.5 million outstanding under its credit agreement.

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 repaid (a) to the extent that 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, purchases of margin stock, 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 $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under the Partnership’s credit agreement upon the occurrence and during the continuance of any event of default. The Partnership’s 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

During the nine months ended September 30, 2016 and 2015, Diamondback completed the following equity offerings:

In January 2016, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $55.33 per share and the Company received proceeds of approximately $254.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In July 2016, the Company completed an underwritten public offering of 6,325,000 shares of common stock, which included 825,000 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 $87.24 per share and the Company received proceeds of approximately $551.8 million from the sale of these shares of common stock, net of estimated offering expenses and underwriting discounts and commissions.

In January 2015, the Company completed an underwritten public offering of 2,012,500 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $59.34 per share and the Company received proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In May 2015, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $72.53 per share and the Company received proceeds of approximately $333.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2015, the Company completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $68.74 per share and the Company received proceeds of approximately $197.6 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 September 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2016 | | | 2015 | | |
| | Income | Shares | Per Share | Income | Shares | Per Share |
| | (in thousands, except per share amounts) | | | | | |
| **Basic:** | | | | | | |
| Net income (loss) attributable to common stock | $ (2,230) | 77,167 | $ (0.03) | $ (156,781) | 65,251 | $ (2.40) |
| **Effect of Dilutive Securities:** | | | | | | |
| Dilutive effect of potential common shares issuable | $ — | 0 | | — | 0 | |
| **Diluted:** | | | | | | |
| Net income (loss) attributable to common stock | $ (2,230) | 77,167 | $ (0.03) | $ (156,781) | 65,251 | $ (2.40) |

| | Nine Months Ended September 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2016 | | | 2015 | | |
| | Income | Shares | Per Share | Income | Shares | Per Share |
| **Basic:** | | | | | | |
| Net income (loss) attributable to common stock | (190,632) | 73,318 | (2.60) | (363,219) | 61,727 | (5.88) |
| **Effect of Dilutive Securities:** | | | | | | |
| Dilutive effect of potential common shares issuable | — | 0 | | — | 0 | |
| **Diluted:** | | | | | | |
| Net income (loss) attributable to common stock | (190,632) | 73,318 | (2.60) | (363,219) | 61,727 | (5.88) |

For the three months and nine months ended September 30, 2016, there were 192,155 shares and 288,739 shares, respectively, that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented. These shares could dilute basic earnings per share in future periods.

## 10. EQUITY-BASED COMPENSATION

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| General and administrative expenses | $ 6,265 | $ 4,402 | $ 20,643 | $ 13,659 |
| Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties | 916 | 1,534 | 5,525 | 5,125 |

***Stock Options***

The following table presents the Company's stock option activity under the Company's 2012 Equity Incentive Plan ("2012 Plan") for the nine months ended September 30, 2016.

| | Options | Weighted Average Exercise Price | Weighted Average Remaining Term | Intrinsic Value |
|---|---|---|---|---|
| | | | (in years) | (in thousands) |
| Outstanding at December 31, 2015 | 39,500 | $ 21.66 | | |
| Exercised | (23,750) | $ 20.96 | | |
| Outstanding at September 30, 2016 | 15,750 | $ 22.72 | 1.35 | $ 1,311 |
| Vested and Expected to vest at September 30, 2016 | 15,750 | $ 22.72 | 1.35 | $ 1,163 |
| Exercisable at September 30, 2016 | — | $ — | 0.00 | $ — |

The aggregate intrinsic value of stock options that were exercised during the nine months ended September 30, 2016 and 2015 was $1.3 million and $8.4 million, respectively. As of September 30, 2016, the unrecognized compensation cost related to unvested stock options was less than $0.1 million. Such cost is expected to be recognized over a weighted-average period of 0.3 years.

***Restricted Stock Units***

The following table presents the Company's restricted stock units activity under the 2012 Plan during the nine months ended September 30, 2016.

| | Restricted Stock Awards & Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Unvested at December 31, 2015 | 159,759 | $ 64.66 |
| Granted | 193,206 | $ 64.66 |
| Vested | (164,851) | $ 63.02 |
| Forfeited | (4,885) | $ 69.41 |
| Unvested at September 30, 2016 | 183,229 | $ 66.02 |

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2016 and 2015 was $11.8 million and $9.8 million, respectively. As of September 30, 2016, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $7.7 million. Such cost is expected to be recognized over a weighted-average period of 1.3 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 two-year or three-year performance period.

In February 2016, eligible employees received performance restricted stock unit awards totaling 174,325 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, 2016 to December 31, 2017 and cliff vest at December 31, 2017. Eligible employees received additional performance restricted stock unit awards totaling 87,163 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, 2016 to December 31, 2018 and cliff vest at December 31, 2018.

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 2016 awards.

| | 2016 | |
|---|---|---|
| | Two-Year Performance Period | Three-Year Performance Period |
| Grant-date fair value | $ 103.41 | $ 102.35 |
| Risk-free rate | 0.86% | 1.10% |
| Company volatility | 41.91% | 42.16% |

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the nine months ended September 30, 2016.

| | Performance Restricted Stock Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Unvested at December 31, 2015 | 90,249 | $ 137.14 |
| Granted | 261,488 | $ 103.06 |
| Forfeited | (6,875) | $ 137.14 |
| Unvested at September 30, 2016 (1) | 344,862 | $ 111.30 |

(1) A maximum of 689,724 units could be awarded based upon the Company's final TSR ranking.

As of September 30, 2016, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $19.9 million. Such cost is expected to be recognized over a weighted-average period of 1.5 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 units entitle 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 nine months ended September 30, 2016.

| | Phantom Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Unvested at December 31, 2015 | 25,348 | $ 16.89 |
| Granted | 21,696 | $ 16.57 |
| Vested | (24,350) | $ 17.27 |
| Forfeited | (1,646) | $ 15.48 |
| Unvested at September 30, 2016 | 21,048 | $ 16.23 |

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2016 was $0.4 million. As of September 30, 2016, 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 1.7 years.

## 11. RELATED PARTY TRANSACTIONS

Immediately upon the completion of the Company’s initial public offering on October 17, 2012, Wexford beneficially owned approximately 44% of the Company’s outstanding common stock. As of September 30, 2016, Wexford beneficially owned less than 1% of the Company’s outstanding common stock. A partner at Wexford serves as Chairman of the Board of Directors of each of the Company and the General Partner. Another partner at Wexford serves as a member of the Board of Directors of the General Partner.

The following table summarizes amounts included in the consolidated statements of operations attributable to related party transactions for the three months and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | *(in thousands)* | | | |
| **Revenues:** | | | | |
| Natural gas sales | $ — | $ — | $ — | $ 2,640 |
| Natural gas liquid sales | — | — | — | 2,544 |
| Total related party revenues | $ — | $ — | $ — | $ 5,184 |
| **Costs and expenses:** | | | | |
| Lease operating expenses | $ 807 | $ — | $ 2,397 | $ — |
| Production and ad valorem taxes | — | — | — | 153 |
| Gathering and transportation | — | — | — | 969 |
| General and administrative expenses | 597 | 665 | 1,600 | 1,672 |
| Total related party costs and expenses | $ 1,404 | $ 665 | $ 3,997 | $ 2,794 |
| **Other Income:** | | | | |
| Other income | $ 40 | $ 40 | $ 128 | $ 119 |
| Total other related party income | $ 40 | $ 40 | $ 128 | $ 119 |

The following table summarizes amounts paid to related parties during the three months and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands) | | | |
| Wexford: | | | | |
| Advisory services | $ 125 | $ 125 | $ 375 | $ 375 |
| Advisory services - The Partnership | — | 125 | — | 375 |
| Total amounts paid to Wexford | $ 125 | $ 250 | $ 375 | $ 750 |
| Wexford related entities: | | | | |
| Bison Drilling and Field Services LLC | $ — | $ 24 | $ — | $ 32 |
| Fasken | 393 | 268 | 1,094 | 672 |
| WT Commercial Portfolio, LLC | 42 | 40 | 126 | 119 |
| Total amounts paid to Wexford related entities | $ 435 | $ 332 | $ 1,220 | $ 823 |
| The Partnership | | | | |
| Lease Bonus | $ 5 | $ — | $ 309 | $ — |
| Total amounts paid to related parties | $ 565 | $ 582 | $ 1,904 | $ 1,573 |

The following table summarizes amounts received from related parties during the three months and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands) | | | |
| Wexford related entities: | | | | |
| Bison Drilling and Field Services LLC | $ 44 | $ 40 | $ 140 | $ 119 |
| Coronado Midstream LLC(1) | $ — | $ — | $ — | $ 4,062 |
| Total amounts received from Wexford related entities | $ 44 | $ 40 | $ 140 | $ 4,181 |

(1) As of March 2015, Coronado Midstream LLC is no longer a related party.

***Advisory Services Agreement - The Company***

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 $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on October 18, 2012, and continues for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term.

***Advisory Services Agreement - The Partnership***

In connection with the closing of the Viper Offering, the Partnership and the 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 the General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement has an initial 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.

***Drilling Services***

Bison Drilling and Field Services LLC ("Bison") 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. During the nine months ended September 30, 2016, the Company did not utilize any Bison rigs.

***Coronado Midstream***

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC, 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 LLC is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream LLC, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. An entity controlled by Wexford had owned an approximately 28% equity interest in Coronado Midstream LLC until Coronado Midstream LLC was sold in March 2015. Coronado Midstream LLC is no longer a related party and any revenues, production and ad valorem taxes and gathering and transportation expense after March 2015 are not classified as those attributable to a related party.

***Midland Corporate Lease***

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with an initial five-year term, which was extended for an additional ten-years in November 2014. The office space is owned by Fasken, which is controlled by an affiliate of Wexford.

***Field Office Lease***

The Company leased field office space in Midland, Texas from an unrelated third party commencing on March 1, 2011. On March 1, 2014, the building was purchased by WT Commercial Portfolio, LLC, which is controlled by an affiliate of Wexford. The term of the lease expires on February 28, 2018. During the third quarter of 2014, the Company entered into a sublease with Bison, in which Bison leased the field office space on the same terms as the Company's lease for the remainder of the lease term.

***The Partnership - Lease Bonus***

During the three months ended September 30, 2016, the Company paid the Partnership $5,000 in lease bonus payments to extend the term of two leases, reflecting an average bonus of $200 per acre. During the nine months ended September 30, 2016, the Company paid the Partnership $0.3 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $1,371 per acre.

## 12. INCOME TAXES

The Company incurred a tax net operating loss ("NOL") for the nine months ended September 30, 2016 due principally to the ability to expense certain intangible drilling and development costs under current regulations. There is no tax refund available to the Company, nor is there any current income tax payable. In light of the impairment of oil and gas properties, management has recorded a $64.9 million valuation allowance against the Company's federal NOLs, bringing the total valuation allowance to $126.0 million. The valuation allowance reduces the Company's deferred assets to a zero value, as management does not believe that it is more-likely-than-not that this portion of the Company's NOLs are realizable. Management believes that the balance of the Company's NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

## 13. 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 fixed price swap contracts and fixed price basis swap contracts to reduce price volatility associated with certain of its oil and natural gas sales. With respect to the Company’s fixed price swap and fixed price basis 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 New York Mercantile Exchange West Texas Intermediate pricing and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub pricing.

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

As of September 30, 2016, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

| | 2016 | | 2017 | |
|---|---|---|---|---|
| | Volume (Bbls/MMBtu) | Fixed Price Swap (per Bbl/MMBtu) | Volume (Bbls/MMBtu) | Fixed Price Swap (per Bbl/MMBtu) |
| Oil Swaps | 276,000 | $ 43.52 | 1,095,000 | $ 45.86 |
| Oil Basis Swaps | 1,288,000 | $ (0.67) | 6,935,000 | $ (0.71) |
| Natural Gas Swaps | 0 | $ — | 3,650,000 | $ 3.10 |

***Balance sheet offsetting of derivative assets and liabilities***

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

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company’s consolidated balance sheets as of September 30, 2016 and December 31, 2015.

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Gross amounts of recognized assets | $ — | $ 4,623 |
| Gross amounts of recognized liabilities | (8,235) | — |
| Net amounts of assets presented in the Consolidated Balance Sheet | $ (8,235) | $ 4,623 |

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

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Current Assets: Derivative instruments | $ — | $ 4,623 |
| Total Assets | $ — | $ 4,623 |
| Current Liabilities: Derivative instruments | $ 6,428 | $ — |
| Noncurrent Liabilities: Derivative instruments | 1,807 | — |
| Total Liabilities | $ 8,235 | $ — |

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:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands) | | | |
| Change in fair value of open non-hedge derivative instruments | $ 2,425 | $ (7,901) | $ (12,858) | $ (77,532) |
| Gain (loss) on settlement of non-hedge derivative instruments | (391) | 35,504 | 4,193 | 104,366 |
| Gain (loss) on derivative instruments | $ 2,034 | $ 27,603 | $ (8,665) | $ 26,834 |

## 14. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

***Assets and Liabilities Measured at Fair Value on a Recurring Basis***

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

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015.

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Fixed price swaps: | | |
| Quoted prices in active markets level 1 | $ — | $ — |
| Significant other observable inputs level 2 | (8,235) | 4,623 |
| Significant unobservable inputs level 3 | — | — |
| Total | $ (8,235) | $ 4,623 |

***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.

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (in thousands) | | | |
| Debt: | | | | |
| Revolving credit facility | $ — | $ — | $ 11,000 | $ 11,000 |
| 7.625% Senior Notes due 2021 | 450,000 | 477,562 | 450,000 | 450,000 |
| Partnership revolving credit facility | 54,500 | 54,500 | 34,500 | 34,500 |

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the September 30, 2016 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.

## 15. COMMITMENTS AND CONTINGENCIES

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.

## 16. SUBSEQUENT EVENTS

***Commodity Contracts***

Subsequent to September 30, 2016, the Company entered into new commodity contracts which include fixed price basis contracts, fixed price swaps of natural gas and costless collars with corresponding put and call options. Under the Company's costless collar contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the put option 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 call option price. If the settlement price is between the put and the call price, there is no payment required. With respect to the Company's fixed price swap and fixed price basis 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 New York Mercantile Exchange West Texas Intermediate pricing and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub pricing.

The following tables present the derivative contracts entered into by the Company subsequent to September 30, 2016. When aggregating multiple contracts, the weighted average contract price is disclosed.

| | Volume (Bbls/MMBtu) | Fixed Price Swap (per Bbl/MMBtu) |
|---|---|---|
| ***January 2017 - December 2017*** | | |
| Oil Basis Swaps | 1,825,000 | $ (0.76) |
| Natural Gas Swaps | 3,650,000 | $ 3.29 |
| ***January 2018 - December 2018*** | | |
| Oil Basis Swaps | 4,380,000 | $ (0.88) |

| | Floor | | Ceiling | |
|---|---|---|---|---|
| | Volume (Bbls) | Fixed Price (per Bbl) | Volume (Bbls) | Fixed Price (per Bbl) |
| ***November 2016 - December 2016*** | | | | |
| Costless Collars | 610,000 | $ 45.00 | 305,000 | $ 54.95 |
| ***January 2017 - June 2017*** | | | | |
| Costless Collars | 1,810,000 | $ 45.00 | 905,000 | $ 54.35 |

***The Company's Credit Facility***

In connection with the Company's fall 2016 redetermination, the agent lender under the credit agreement has recommended that the Company's borrowing base be increased to $1.0 billion. Notwithstanding such adjustment, the Company intends to continue to limit the lenders' aggregate commitment to $500.0 million.

***The Partnership's Credit Facility***

In connection with the Partnership's fall 2016 redetermination, the agent lender under the credit agreement has recommended that the Partnership's borrowing base be increased to $275.0 million.

***4.75% Senior Notes due 2024***

On October 28, 2016, the Company completed an offering of $500.0 million in aggregate principal amount of its 4.75% Senior Notes due 2024 (the "2024 Senior Notes"). The 2024 Senior Notes bear interest at a rate of 4.75% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017 and will mature on November 1, 2024. As of the closing date, the 2024 Senior Notes are fully and unconditionally guaranteed by Diamondback O&G LLC and Diamondback E&P LLC and will also be guaranteed by any future restricted subsidiary of the Company. The Company received $496.0 million in net proceeds from the offering of the 2024 Senior Notes, which were used, in part, to repurchase all of the Company's outstanding 2021 Senior Notes accepted for purchase in a related tender offer, to pay fees and expenses thereof and to redeem the 2021 Senior Notes that remained outstanding after completion of the tender offer. For a discussion of the tender offer and related redemption, see "-Tender Offer and Redemption-Existing 2021 Senior Notes" below. The Company intends to use the remaining net proceeds from the offering of the 2024 Senior Notes for general corporate purposes, which may include the funding of a portion of the Company's capital development plans.

***Tender Offer and Redemption-Existing 2021 Senior Notes***

On October 21, 2016, the Company commenced a cash tender offer to purchase any and all of its 2021 Senior Notes, which tender offer expired on October 27, 2016 and settled on October 28, 2016. Holders of the 2021 Senior

Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2021 Senior Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,059.69 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $330.1 million principal amount of the 2021 Senior Notes was validly tendered in the tender offer. The remaining 2021 Senior Notes that were not tendered in the tender offer were redeemed by the Company. The redemption payment included approximately $119.9 million of outstanding principal at a redemption price of 105.719% of the principal amount of the redeemed 2021 Senior Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 28, 2016, the indenture governing the 2021 Senior Notes was fully satisfied and discharged. The cash tender offer for the 2021 Senior Notes and redemption of the remaining 2021 Senior Notes were funded with a portion of the net proceeds from the offering of the 2024 Senior Notes in the aggregate principal amount of $500.0 million discussed in more detail above under the heading “–4.75% Senior Notes due 2024.”

## 17. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P LLC, Diamondback O&G LLC 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 Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy Partners LLC (the “Non-Guarantor Subsidiaries”) as unrestricted subsidiaries under the Indenture and, upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 17 is referred to as the “Parent”), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries 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.

**Condensed Consolidated Balance Sheet**
**September 30, 2016**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 133,279 | $ 26,232 | $ 7,758 | $ — | $ 167,269 |
| Restricted cash | — | — | 500 | — | 500 |
| Accounts receivable | — | 75,583 | 9,918 | — | 85,501 |
| Accounts receivable - related party | — | 13 | — | — | 13 |
| Intercompany receivable | 2,915,582 | 317,103 | — | (3,232,685) | — |
| Inventories | — | 1,969 | — | — | 1,969 |
| Other current assets | 213 | 2,712 | 93 | — | 3,018 |
| Total current assets | 3,049,074 | 423,612 | 18,269 | (3,232,685) | 258,270 |
| Property and equipment: | | | | | |
| Oil and natural gas properties, at cost, based on the full cost method of accounting | — | 4,249,936 | 692,816 | (559) | 4,942,193 |
| Pipeline and gas gathering assets | — | 8,362 | — | — | 8,362 |
| Other property and equipment | — | 58,205 | — | — | 58,205 |
| Accumulated depletion, depreciation, amortization and impairment | — | (1,652,185) | (140,613) | 8,018 | (1,784,780) |
| Net property and equipment | — | 2,664,318 | 552,203 | 7,459 | 3,223,980 |
| Investment in subsidiaries | (73,559) | — | — | 73,559 | — |
| Other assets | — | 8,533 | 34,897 | — | 43,430 |
| Total assets | $ 2,975,515 | $ 3,096,463 | $ 605,369 | $ (3,151,667) | $ 3,525,680 |
| **Liabilities and Stockholders' Equity** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable-trade | $ — | $ 38,797 | $ 37 | $ — | $ 38,834 |
| Accounts payable-related party | 2 | — | — | — | 2 |
| Intercompany payable | — | 3,232,685 | — | (3,232,685) | — |
| Other current liabilities | 17,331 | 117,105 | 1,753 | — | 136,189 |
| Total current liabilities | 17,333 | 3,388,587 | 1,790 | (3,232,685) | 175,025 |
| Long-term debt | 443,313 | — | 54,500 | — | 497,813 |
| Derivative instruments | — | 1,807 | — | — | 1,807 |
| Asset retirement obligations | — | 15,740 | — | — | 15,740 |
| Total liabilities | 460,646 | 3,406,134 | 56,290 | (3,232,685) | 690,385 |
| Commitments and contingencies | | | | | |
| Stockholders' equity | 2,514,869 | (309,671) | 549,079 | (239,408) | 2,514,869 |
| Non-controlling interest | — | — | — | 320,426 | 320,426 |
| Total equity | 2,514,869 | (309,671) | 549,079 | 81,018 | 2,835,295 |
| Total liabilities and equity | $ 2,975,515 | $ 3,096,463 | $ 605,369 | $ (3,151,667) | $ 3,525,680 |

**Condensed Consolidated Balance Sheet**
**December 31, 2015**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 148 | $ 19,428 | $ 539 | $ — | $ 20,115 |
| Restricted cash | — | — | 500 | — | 500 |
| Accounts receivable | — | 67,942 | 9,369 | 2 | 77,313 |
| Accounts receivable - related party | — | 1,591 | — | — | 1,591 |
| Intercompany receivable | 2,246,846 | 205,915 | — | (2,452,761) | — |
| Inventories | — | 1,728 | — | — | 1,728 |
| Other current assets | 450 | 6,572 | 476 | — | 7,498 |
| Total current assets | 2,247,444 | 303,176 | 10,884 | (2,452,759) | 108,745 |
| Property and equipment: | | | | | |
| Oil and natural gas properties, at cost, based on the full cost method of accounting | — | 3,400,381 | 554,992 | — | 3,955,373 |
| Pipeline and gas gathering assets | — | 7,174 | — | — | 7,174 |
| Other property and equipment | — | 48,621 | — | — | 48,621 |
| Accumulated depletion, depreciation, amortization and impairment | — | (1,347,296) | (71,659) | 5,412 | (1,413,543) |
| Net property and equipment | — | 2,108,880 | 483,333 | 5,412 | 2,597,625 |
| Investment in subsidiaries | 79,417 | — | — | (79,417) | — |
| Other assets | 102 | 8,733 | 35,514 | — | 44,349 |
| Total assets | $ 2,326,963 | $ 2,420,789 | $ 529,731 | $ (2,526,764) | $ 2,750,719 |
| **Liabilities and Stockholders' Equity** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable-trade | $ — | $ 20,007 | $ 1 | $ — | $ 20,008 |
| Accounts payable-related party | 1 | 212 | 4 | — | 217 |
| Intercompany payable | — | 2,452,759 | — | (2,452,759) | — |
| Other current liabilities | 8,683 | 112,431 | 82 | — | 121,196 |
| Total current liabilities | 8,684 | 2,585,409 | 87 | (2,452,759) | 141,421 |
| Long-term debt | 442,307 | 11,000 | 34,500 | — | 487,807 |
| Asset retirement obligations | — | 12,518 | — | — | 12,518 |
| Total liabilities | 450,991 | 2,608,927 | 34,587 | (2,452,759) | 641,746 |
| Commitments and contingencies | | | | | |
| Stockholders' equity | 1,875,972 | (188,138) | 495,144 | (307,006) | 1,875,972 |
| Non-controlling interest | — | — | — | 233,001 | 233,001 |
| Total equity | 1,875,972 | (188,138) | 495,144 | (74,005) | 2,108,973 |
| Total liabilities and equity | $ 2,326,963 | $ 2,420,789 | $ 529,731 | $ (2,526,764) | $ 2,750,719 |

**Condensed Consolidated Statement of Operations**
**Three Months Ended September 30, 2016**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Revenues:** | | | | | |
| Oil sales | $ — | $ 108,273 | $ — | $ 18,080 | $ 126,353 |
| Natural gas sales | — | 5,581 | — | 753 | 6,334 |
| Natural gas liquid sales | — | 8,285 | — | 1,159 | 9,444 |
| Royalty income | — | — | 19,992 | (19,992) | — |
| Lease bonus income | — | — | 5 | (5) | — |
| Total revenues | — | 122,139 | 19,997 | (5) | 142,131 |
| **Costs and expenses:** | | | | | |
| Lease operating expenses | — | 22,180 | — | — | 22,180 |
| Production and ad valorem taxes | — | 7,694 | 1,429 | — | 9,123 |
| Gathering and transportation | — | 2,773 | 70 | — | 2,843 |
| Depreciation, depletion and amortization | — | 38,572 | 6,751 | (577) | 44,746 |
| Impairment of oil and natural gas properties | — | 46,368 | — | — | 46,368 |
| General and administrative expenses | 5,736 | 3,019 | 1,153 | — | 9,908 |
| Asset retirement obligation accretion expense | — | 270 | — | — | 270 |
| Total costs and expenses | 5,736 | 120,876 | 9,403 | (577) | 135,438 |
| **Income (loss) from operations** | (5,736) | 1,263 | 10,594 | 572 | 6,693 |
| **Other income (expense)** | | | | | |
| Interest expense | (8,847) | (729) | (658) | — | (10,234) |
| Other income | 199 | 442 | 266 | — | 907 |
| Gain on derivative instruments, net | — | 2,034 | — | — | 2,034 |
| Total other expense, net | (8,648) | 1,747 | (392) | — | (7,293) |
| **Net income (loss)** | (14,384) | 3,010 | 10,202 | 572 | (600) |
| Net income attributable to non-controlling interest | — | — | — | 1,630 | 1,630 |
| **Net income (loss) attributable to Diamondback Energy, Inc.** | $ (14,384) | $ 3,010 | $ 10,202 | $ (1,058) | $ (2,230) |

**Condensed Consolidated Statement of Operations**
**Three Months Ended September 30, 2015**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Revenues:** | | | | | |
| Oil sales | $ — | $ 84,002 | $ — | $ 17,305 | $ 101,307 |
| Natural gas sales | — | 4,905 | — | 768 | 5,673 |
| Natural gas liquid sales | — | 4,262 | — | 704 | 4,966 |
| Royalty income | — | — | 18,777 | (18,777) | — |
| Total revenues | — | 93,169 | 18,777 | — | 111,946 |
| **Costs and expenses:** | | | | | |
| Lease operating expenses | — | 22,189 | — | — | 22,189 |
| Production and ad valorem taxes | — | 7,280 | 1,686 | — | 8,966 |
| Gathering and transportation | — | 1,521 | 167 | — | 1,688 |
| Depreciation, depletion and amortization | — | 43,655 | 8,737 | (17) | 52,375 |
| Impairment of oil and natural gas properties | — | 273,737 | — | — | 273,737 |
| General and administrative expenses | 4,020 | 1,864 | 1,642 | — | 7,526 |
| Asset retirement obligation accretion expense | — | 238 | — | — | 238 |
| Total costs and expenses | 4,020 | 350,484 | 12,232 | (17) | 366,719 |
| **Income (loss) from operations** | (4,020) | (257,315) | 6,545 | 17 | (254,773) |
| **Other income (expense)** | | | | | |
| Interest expense | (8,914) | (1,361) | (358) | — | (10,633) |
| Other income | — | 132 | 168 | — | 300 |
| Gain on derivative instruments, net | — | 27,603 | — | — | 27,603 |
| Total other income (expense), net | (8,914) | 26,374 | (190) | — | 17,270 |
| Income (loss) before income taxes | (12,934) | (230,941) | 6,355 | 17 | (237,503) |
| Benefit from income taxes | (81,461) | — | — | — | (81,461) |
| **Net income (loss)** | 68,527 | (230,941) | 6,355 | 17 | (156,042) |
| Net income attributable to non-controlling interest | — | — | — | 739 | 739 |
| **Net income (loss) attributable to Diamondback Energy, Inc.** | $ 68,527 | $ (230,941) | $ 6,355 | $ (722) | $ (156,781) |

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

**Condensed Consolidated Statement of Operations**
**Nine Months Ended September 30, 2016**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Revenues:** | | | | | |
| Oil sales | $ — | $ 260,180 | $ — | $ 46,518 | $ 306,698 |
| Natural gas sales | — | 12,561 | — | 1,904 | 14,465 |
| Natural gas liquid sales | — | 18,440 | — | 2,492 | 20,932 |
| Royalty income | — | — | 50,914 | (50,914) | — |
| Lease bonus income | — | — | 309 | (309) | — |
| Total revenues | — | 291,181 | 51,223 | (309) | 342,095 |
| **Costs and expenses:** | | | | | |
| Lease operating expenses | — | 59,080 | — | — | 59,080 |
| Production and ad valorem taxes | — | 21,110 | 4,134 | — | 25,244 |
| Gathering and transportation | — | 7,815 | 247 | 2 | 8,064 |
| Depreciation, depletion and amortization | — | 107,807 | 21,485 | (2,606) | 126,686 |
| Impairment of oil and natural gas properties | — | 198,067 | 47,469 | — | 245,536 |
| General and administrative expenses | 20,110 | 8,192 | 4,109 | — | 32,411 |
| Asset retirement obligation accretion expense | — | 770 | — | — | 770 |
| Total costs and expenses | 20,110 | 402,841 | 77,444 | (2,604) | 497,791 |
| **Loss from operations** | (20,110) | (111,660) | (26,221) | 2,295 | (155,696) |
| **Other income (expense)** | | | | | |
| Interest expense | (26,549) | (2,173) | (1,544) | — | (30,266) |
| Other income | 319 | 966 | 612 | (250) | 1,647 |
| Loss on derivative instruments, net | — | (8,665) | — | — | (8,665) |
| Total other expense, net | (26,230) | (9,872) | (932) | (250) | (37,284) |
| Income (loss) before income taxes | (46,340) | (121,532) | (27,153) | 2,045 | (192,980) |
| Provision for income taxes | 368 | — | — | — | 368 |
| **Net income (loss)** | (46,708) | (121,532) | (27,153) | 2,045 | (193,348) |
| Net loss attributable to non-controlling interest | — | — | — | (2,716) | (2,716) |
| **Net income (loss) attributable to Diamondback Energy, Inc.** | $ (46,708) | $ (121,532) | $ (27,153) | $ 4,761 | $ (190,632) |

**Condensed Consolidated Statement of Operations**
**Nine Months Ended September 30, 2015**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| **Revenues:** | | | | | |
| Oil sales | $ — | $ 250,704 | $ — | $ 51,146 | $ 301,850 |
| Natural gas sales | — | 12,580 | — | 1,851 | 14,431 |
| Natural gas liquid sales | — | 14,185 | — | 1,944 | 16,129 |
| Royalty income | — | — | 54,941 | (54,941) | — |
| Total revenues | — | 277,469 | 54,941 | — | 332,410 |
| **Costs and expenses:** | | | | | |
| Lease operating expenses | — | 65,117 | — | — | 65,117 |
| Production and ad valorem taxes | — | 20,605 | 4,431 | — | 25,036 |
| Gathering and transportation | — | 4,176 | 167 | — | 4,343 |
| Depreciation, depletion and amortization | — | 141,923 | 26,587 | 638 | 169,148 |
| Impairment expense | — | 597,188 | — | — | 597,188 |
| General and administrative expenses | 12,773 | 6,172 | 4,501 | — | 23,446 |
| Asset retirement obligation accretion expense | — | 588 | — | — | 588 |
| Total costs and expenses | 12,773 | 835,769 | 35,686 | 638 | 884,866 |
| **Income (loss) from operations** | (12,773) | (558,300) | 19,255 | (638) | (552,456) |
| **Other income (expense)** | | | | | |
| Interest expense | (26,735) | (3,936) | (733) | — | (31,404) |
| Other income | 1 | 287 | 960 | — | 1,248 |
| Gain on derivative instruments, net | — | 26,834 | — | — | 26,834 |
| Total other income (expense), net | (26,734) | 23,185 | 227 | — | (3,322) |
| Income (loss) before income taxes | (39,507) | (535,115) | 19,482 | (638) | (555,778) |
| Benefit from income taxes | (194,823) | — | — | — | (194,823) |
| **Net income (loss)** | 155,316 | (535,115) | 19,482 | (638) | (360,955) |
| Net income attributable to non-controlling interest | — | — | — | 2,264 | 2,264 |
| **Net income (loss) attributable to Diamondback Energy, Inc.** | $ 155,316 | $ (535,115) | $ 19,482 | $ (2,902) | $ (363,219) |

**Condensed Consolidated Statement of Cash Flows**
**Nine Months Ended September 30, 2016**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| Net cash provided by (used in) operating activities | $ (19,148) | $ 198,944 | $ 46,550 | $ — | $ 226,346 |
| Cash flows from investing activities: | | | | | |
| Additions to oil and natural gas properties | — | (242,246) | — | — | (242,246) |
| Acquisition of leasehold interests | — | (591,785) | — | — | (591,785) |
| Acquisition of royalty interests | — | — | (137,782) | — | (137,782) |
| Purchase of other property and equipment | — | (9,805) | — | — | (9,805) |
| Proceeds from sale of assets | — | 1,566 | — | — | 1,566 |
| Equity investments | — | (800) | — | — | (800) |
| Intercompany transfers | (652,211) | 652,211 | — | — | — |
| Other investing activities | — | (1,188) | — | — | (1,188) |
| Net cash used in investing activities | (652,211) | (192,047) | (137,782) | — | (982,040) |
| Cash flows from financing activities: | | | | | |
| Proceeds from borrowing on credit facility | — | — | 98,000 | — | 98,000 |
| Repayment on credit facility | — | (11,000) | (78,000) | — | (89,000) |
| Debt issuance costs | — | (93) | (35) | — | (128) |
| Public offering costs | (356) | — | (444) | — | (800) |
| Proceeds from public offerings | 775,095 | — | 125,580 | — | 900,675 |
| Distribution from subsidiary | 40,253 | — | — | (40,253) | — |
| Exercise of stock options | 498 | — | — | — | 498 |
| Distribution to non-controlling interest | — | — | (46,650) | 40,253 | (6,397) |
| Intercompany transfers | (11,000) | 11,000 | — | — | — |
| Net cash provided by (used in) financing activities | 804,490 | (93) | 98,451 | — | 902,848 |
| Net increase in cash and cash equivalents | 133,131 | 6,804 | 7,219 | — | 147,154 |
| Cash and cash equivalents at beginning of period | 148 | 19,428 | 539 | — | 20,115 |
| Cash and cash equivalents at end of period | $ 133,279 | $ 26,232 | $ 7,758 | $ — | $ 167,269 |

**Condensed Consolidated Statement of Cash Flows**
**Nine Months Ended September 30, 2015**
**(In thousands)**

| | Parent | Guarantor Subsidiaries | Non–Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| Net cash provided by (used in) operating activities | $ (19,081) | $ 312,712 | $ 45,973 | $ — | $ 339,604 |
| Cash flows from investing activities: | | | | | |
| Additions to oil and natural gas properties | — | (326,538) | 71 | — | (326,467) |
| Acquisition of leasehold interests | — | (425,507) | — | — | (425,507) |
| Acquisition of royalty interests | — | — | (32,291) | — | (32,291) |
| Purchase of other property and equipment | — | (992) | — | — | (992) |
| Proceeds from sale of assets | — | 97 | — | — | 97 |
| Equity investments | — | (2,702) | — | — | (2,702) |
| Intercompany transfers | (147,214) | 147,214 | — | — | — |
| Other investing activities | — | (2) | — | — | (2) |
| Net cash used in investing activities | (147,214) | (608,430) | (32,220) | — | (787,864) |
| Cash flows from financing activities: | | | | | |
| Proceeds from borrowing on credit facility | — | 363,501 | 29,000 | — | 392,501 |
| Repayment on credit facility | — | (577,001) | — | — | (577,001) |
| Proceeds from public offerings | 650,688 | — | — | — | 650,688 |
| Distribution from subsidiary | 46,496 | — | — | (46,496) | — |
| Distribution to non-controlling interest | — | — | (52,609) | 46,496 | (6,113) |
| Intercompany transfers | (532,800) | 532,800 | — | — | — |
| Other financing activities | 2,132 | — | (303) | — | 1,829 |
| Net cash provided by (used in) financing activities | 166,516 | 319,300 | (23,912) | — | 461,904 |
| Net increase (decrease) in cash and cash equivalents | 221 | 23,582 | (10,159) | — | 13,644 |
| Cash and cash equivalents at beginning of period | 6 | 15,067 | 15,110 | — | 30,183 |
| Cash and cash equivalents at end of period | $ 227 | $ 38,649 | $ 4,951 | $ — | $ 43,827 |

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

*The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report as well as our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015. 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.

The following table sets forth our production data for the periods indicated:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Oil (Bbls) | 73% | 73% | 73% | 74% |
| Natural gas (Mcf) | 11% | 11% | 11% | 11% |
| Natural gas liquids (Bbls) | 16% | 16% | 16% | 15% |
| | 100% | 100% | 100% | 100% |

On September 30, 2016, our net acreage position in the Permian Basin was approximately 105,787 net acres.

The challenging commodity price environment that we experienced in 2015 has continued in 2016, with the posted price of WTI reaching a 12-year low of $26.19 per barrel on February 11, 2016. Commodity prices improved during the third quarter 2016, but continue to be volatile. We believe we remain well-positioned in this environment. During 2015, we again demonstrated our operational focus on achieving best-in-class execution, low-cost operations and a conservative balance sheet as we continued to reduce drilling days, well costs and operating expenses while maintaining what we believe to be a peer leading leverage ratio. We have continued our operational focus in 2016 and have further decreased drilling times, well costs and operating expenses. Our leading-edge Midland Basin costs to drill, complete and equip wells are currently below $6.0 million for a 10,000 foot lateral well and below $5.0 million for a 7,500 foot lateral well. During the third quarter of 2016, we drilled two 5,000 foot lateral wells on our Spanish Trail acreage for less than $1.5 million each from spud to rig release. We also successfully drilled a 13,100 foot lateral well in Midland County which is our longest lateral horizontal well drilled to date. With recent improvement in oil prices, we are currently operating five horizontal rigs and two completion crews. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions. We continue to evaluate adding additional rigs in 2017 if commodity prices strengthen.

**2016 Highlights**

*Recent Equity Offerings*

In January 2016, we completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $55.33 per share and we received proceeds of approximately $254.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On July 18, 2016, we completed an underwritten public offering of 6,325,000 shares of common stock, which included 825,000 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 $87.24 per share and we received proceeds of approximately $551.8 million from the sale of these shares of common stock, net of estimated offering expenses and underwriting discounts and commissions.

On August 1, 2016, Viper completed an underwritten public offering of 8,050,000 common units, which included 1,050,000 common units issued pursuant to an option to purchase additional common units granted to the underwriter. In this offering, we purchased 2,000,000 common units from the underwriter at $15.60 per unit, which is the price per common unit paid by the underwriter to Viper. Following this public offering, we had an approximate 83% limited partner interest in Viper. Viper received proceeds from this offering of approximately $125.1 million, net of estimated offering expenses and underwriting discounts and commissions, which Viper used to fund the purchase price for its August acquisition described below under the heading "-Recent Acquisitions by Viper" and repay outstanding borrowings under Viper's revolving credit facility.

*Offering of the 2024 Senior Notes*

On October 28, 2016, we completed an offering of $500.0 million in aggregate principal amount of our 4.75% Senior Notes due 2024, which we refer to as the 2024 Senior Notes. We received $496.0 million in net proceeds from the offering of the 2024 Senior Notes, which were used primarily to repurchase all of the Company's outstanding 7.625% Senior Notes due 2021, which we refer to as the 2021 Senior Notes, accepted for purchase in a related tender offer, to pay fees and expenses thereof and to redeem the 2021 Senior Notes that remained outstanding after completion of the tender offer. See "Tender Offer and Redemption-Existing 2021 Senior Notes" below. We intend to use the remaining net proceeds from the offering of the 2024 Senior Notes for general corporate purposes, which may include the funding of a portion of the our capital development plans.

*Tender Offer and Redemption-Existing 2021 Senior Notes*

On October 21, 2016, we commenced a cash tender offer to purchase any and all of our 2021 Senior Notes, which tender offer expired on October 27, 2016 and settled on October 28, 2016. An aggregate of $330.1 million principal amount of the 2021 Senior Notes was validly tendered in the tender offer. The remaining 2021 Senior Notes that were not tendered in the tender offer were redeemed by us, and the indenture governing the 2021 Senior Notes was fully satisfied and discharged. The cash tender offer for the 2021 Senior Notes and redemption of the remaining 2021 Senior Notes were funded with a portion of the net proceeds from the offering of the 2024 Senior Notes.

*Our Recent Acquisition*

On September 1, 2016, we acquired from an unrelated third party leasehold interests and related assets in the Southern Delaware Basin for an aggregate purchase price of $560.0 million, subject to certain adjustments. This transaction included approximately 38,765 gross (19,180 net) acres primarily in Reeves and Ward counties, 19 gross producing vertical wells, 11 gross producing horizontal wells, saltwater disposal and gathering infrastructure and other related assets. We estimate that there are 290 net potential horizontal drilling locations across four zones with an average lateral length of approximately 9,500 feet on this acreage. We financed this acquisition with the net proceeds of the July 2016 equity offering discussed above and cash on hand.

*Recent Acquisitions by Viper*

On July 22, 2016, Viper acquired from an unrelated third party mineral interests underlying 7,487 gross (601 net royalty) acres in the Midland Basin, with approximately 300 BOE/d of estimated August 2016 net production, for $79.0 million.

In July 2016, Viper also acquired from unrelated third parties mineral interests underlying an additional 9,281 gross (152 net royalty) acres in the Permian Basin for an aggregate of $11.7 million.

The purchase price for each of the above described Viper acquisitions was primarily funded with borrowings under Viper's revolving credit facility.

On August 16, 2016, Viper acquired from an unrelated third party mineral interests in 650 gross (142 net royalty) acres in the Delaware Basin, with approximately 200 BOE/d of estimated August 2016 net production, for approximately $31.4 million, subject to post-closing adjustments. Viper used a portion of the net proceeds from its August 2016 public offering of common units to fund this acquisition.

*Operational Update*

We drilled 17 gross (13 net) horizontal wells and completed 21 gross (18 net) horizontal wells in the third quarter of 2016. We also participated in the drilling of two gross (one net) horizontal wells and the completion of seven gross (three net) non-operated wells during the third quarter of 2016. Our operated completions consisted of ten Lower Spraberry, two Middle Spraberry, two Wolfcamp A, and seven Wolfcamp B wells. Ten of the wells were in Midland County, four in Glasscock County and the remainder in various other counties. The four Glasscock County wells all targeted the Wolfcamp B horizon to hold those depths. Two of the wells have approximately two mile laterals. The Target B 3905 WB and the Target D 3904 WB are flowing and achieved an average 30-day flowing two-stream initial production, or IP, rates of 1,425 BOE/d (85% oil) from an average lateral length of 10,050 feet. The Riley D 1819 4WB and the Riley E 1819 5WB are flowing and achieved an average 30-day IP rates of 1,067 BOE/d (85% oil) from an average lateral length of 8,106 feet.

We also recently completed a three-well pad in Howard County targeting the Lower Spraberry, Wolfcamp A and Wolfcamp B horizons with an average completed lateral length of 9,725 feet. The peak 24-hour IP rates to date from the Reed 1A 1WA and Reed 1A 1WB are 2,149 BOE/d (89% oil) and 1,801 BOE/d (90% oil), respectively, while the Lower Spraberry well is producing 797 BOE/d ( 89% oil) and still cleaning up.

Also during the third quarter of 2016, we drilled two wells in Glasscock County and one well in Martin County with average lateral lengths of 10,980 feet in an average of 11.5 days from spud to total depth. In addition, we successfully drilled two wells in Midland County with lateral lengths over 13,000 feet, our longest horizontal wells drilled to date.

In October 2016, we added a fifth drilling rig and will consider a sixth rig in early 2017 targeting the Southern Delaware Basin. We continue to operate two completion crews and expect that we will have completed our inventory of uncompleted wells by the end of 2016.

The following table summarizes our average daily production for the periods presented:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Oil (Bbls)/d | 32,618 | 24,956 | 29,398 | 23,589 |
| Natural Gas (Mcf)/d | 29,054 | 23,068 | 27,577 | 20,235 |
| Natural Gas Liquids (Bbls)/d | 7,463 | 5,281 | 6,048 | 4,615 |
| Total average production per day | 44,923 | 34,082 | 40,042 | 31,576 |

Our average daily production for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 increased 10,841 BOE/d, or 31.8%. Our average daily production for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015 increased 8,466 BOE/d, or 26.8%.

**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. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

The following table presents the breakdown of our revenues for the following periods:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Revenues | | | | |
| Oil sales | 89% | 91% | 90% | 91% |
| Natural gas sales | 4% | 5% | 4% | 4% |
| Natural gas liquid sales | 7% | 4% | 6% | 5% |
| | 100% | 100% | 100% | 100% |

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 2015, West Texas Intermediate posted prices ranged from $34.55 to $61.36 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.63 to $3.32 per MMBtu. On September 30, 2016, 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 $2.84 per MMBtu. Lower commodity prices may not only decrease our revenues, but also potentially the amount of oil and natural gas that we can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be redetermined at the discretion of our lenders.

As a result of the decline in prices during the nine months ended September 30, 2016, the Company recorded a non-cash impairment of its oil and gas properties of $245.5 million.

Although commodity prices continued to improve during the third quarter of 2016, they remain volatile. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, we may incur an additional non-cash full cost impairment in the fourth quarter of 2016, which will have an adverse effect on our results of operations.

**Results of Operations**

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands, except Bbl, Mcf and BOE amounts) | | | |
| Revenues | | | | |
| Oil, natural gas liquids and natural gas | $ 142,131 | $ 111,946 | $ 342,095 | $ 332,410 |
| Operating Expenses | | | | |
| Lease operating expenses | 22,180 | 22,189 | 59,080 | 65,117 |
| Production and ad valorem taxes | 9,123 | 8,966 | 25,244 | 25,036 |
| Gathering and transportation | 2,843 | 1,688 | 8,064 | 4,343 |
| Depreciation, depletion and amortization | 44,746 | 52,375 | 126,686 | 169,148 |
| Impairment of oil and natural gas properties | 46,368 | 273,737 | 245,536 | 597,188 |
| General and administrative expenses | 9,908 | 7,526 | 32,411 | 23,446 |
| Asset retirement obligation accretion expense | 270 | 238 | 770 | 588 |
| Total expenses | 135,438 | 366,719 | 497,791 | 884,866 |
| Income (loss) from operations | 6,693 | (254,773) | (155,696) | (552,456) |
| Net interest expense | (10,234) | (10,633) | (30,266) | (31,404) |
| Other income | 907 | 300 | 1,647 | 1,248 |
| Gain (loss) on derivative instruments, net | 2,034 | 27,603 | (8,665) | 26,834 |
| Total other expense, net | (7,293) | 17,270 | (37,284) | (3,322) |
| Loss before income taxes | (600) | (237,503) | (192,980) | (555,778) |
| Income tax provision (benefit) | — | (81,461) | 368 | (194,823) |
| Net loss | (600) | (156,042) | (193,348) | (360,955) |
| Net income (loss) attributable to non-controlling interest | 1,630 | 739 | (2,716) | 2,264 |
| Net loss attributable to Diamondback Energy, Inc. | $ (2,230) | $ (156,781) | $ (190,632) | $ (363,219) |

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands, except Bbl, Mcf and BOE amounts) | | | |
| **Production Data:** | | | | |
| Oil (Bbls) | 3,000,845 | 2,295,940 | 8,054,945 | 6,439,699 |
| Natural gas (Mcf) | 2,672,988 | 2,122,248 | 7,556,147 | 5,524,138 |
| Natural gas liquids (Bbls) | 686,563 | 485,871 | 1,657,189 | 1,259,777 |
| Combined volumes (BOE) | 4,132,906 | 3,135,519 | 10,971,492 | 8,620,166 |
| Daily combined volumes (BOE/d) | 44,923 | 34,082 | 40,042 | 31,576 |
| | | | | |
| **Average Prices:** | | | | |
| Oil (per Bbl) | $ 42.11 | $ 44.12 | $ 38.08 | $ 46.87 |
| Natural gas (per Mcf) | 2.37 | 2.67 | 1.91 | 2.61 |
| Natural gas liquids (per Bbl) | 13.76 | 10.22 | 12.63 | 12.80 |
| Combined (per BOE) | 34.39 | 35.70 | 31.18 | 38.56 |
| Oil, hedged($ per Bbl)(1) | 41.98 | 59.59 | 38.60 | 63.08 |
| Average price, hedged($ per BOE)(1) | 34.30 | 47.03 | 31.56 | 50.67 |
| | | | | |
| **Average Costs per BOE:** | | | | |
| Lease operating expense | $ 5.37 | $ 7.08 | $ 5.38 | $ 7.55 |
| Production and ad valorem taxes | 2.21 | 2.86 | 2.30 | 2.90 |
| Gathering and transportation expense | 0.69 | 0.54 | 0.73 | 0.50 |
| General and administrative - cash component | 0.88 | 1.01 | 1.07 | 1.14 |
| Total operating expense - cash | 9.15 | 11.49 | 9.48 | 12.09 |
| | | | | |
| General and administrative - non-cash component | 1.52 | 1.39 | 1.88 | 1.58 |
| Depreciation, depletion, and amortization | 10.83 | 16.70 | 11.55 | 19.62 |
| Interest expense | 2.48 | 3.39 | 2.76 | 3.64 |
| Total expenses | 14.83 | 21.48 | 16.19 | 24.84 |
| | | | | |
| Average realized oil price ($/Bbl) | $ 42.11 | $ 44.12 | $ 38.08 | $ 46.87 |
| Average NYMEX ($/Bbl) | 44.85 | 46.49 | 41.35 | 50.94 |
| Differential to NYMEX | (2.74) | (2.37) | (3.27) | (4.07) |
| Average realized oil price to NYMEX percentage | 94% | 95% | 92% | 92% |
| | | | | |
| Average realized natural gas price ($/Mcf) | $ 2.37 | $ 2.67 | $ 1.91 | $ 2.61 |
| Average NYMEX ($/Mcf) | 2.88 | 2.76 | 2.34 | 2.80 |
| Differential to NYMEX | (0.51) | (0.09) | (0.43) | (0.19) |
| Average realized natural gas price to NYMEX percentage | 82% | 97% | 82% | 93% |
| | | | | |
| Average realized natural gas liquids price ($/Bbl) | $ 13.76 | $ 10.22 | $ 12.63 | $ 12.80 |
| Average NYMEX oil price ($/Bbl) | 44.85 | 46.49 | 41.35 | 50.94 |
| Average realized natural gas liquids price to NYMEX oil price percentage | 31% | 22% | 31% | 25% |

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include realized gains and losses on cash settlements for commodity derivatives, which we do not designate for hedge accounting.

***Comparison of the Three Months Ended September 30, 2016 and 2015***

***Oil, Natural Gas Liquids and Natural Gas Revenues.*** Our oil, natural gas liquids and natural gas revenues increased by approximately $30.2 million, or 27%, to $142.1 million for the three months ended September 30, 2016 from $111.9 million for the three months ended September 30, 2015. 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 10,841 BOE/d to 44,923 BOE/d during the three months ended September 30, 2016 from 34,082 BOE/d during the three months ended September 30, 2015. The total increase in revenue of approximately $30.2 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes partially offset by lower average sales prices for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 704,905 Bbls of oil, 200,692 Bbls of natural gas liquids and 550,740 Mcf of natural gas for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015.

The net dollar effect of the decreases in prices of approximately $4.4 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 $34.6 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 | $ (2.01) | 3,000,845 | $ (6,044) |
| Natural gas liquids | 3.54 | 686,563 | 2,430 |
| Natural gas | (0.30) | 2,672,988 | (802) |
| Total revenues due to change in price | | | $ (4,416) |

| | Change in production volumes(1) | Prior period Average Prices | Total net dollar effect of change |
|---|---|---|---|
| | | | (in thousands) |
| Effect of changes in production volumes: | | | |
| Oil | 704,905 | $ 44.12 | $ 31,080 |
| Natural gas liquids | 200,692 | 10.22 | 2,051 |
| Natural gas | 550,740 | 2.67 | 1,470 |
| Total revenues due to change in production volumes | | | 34,601 |
| Total change in revenues | | | $ 30,185 |

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

***Lease Operating Expense.*** Lease operating expense was $22.2 million ($5.37 per BOE) for the three months ended September 30, 2016 and $22.2 million ($7.08 per BOE) for the three months ended September 30, 2015. The decrease in lease operating expense per BOE was a result of efficiencies we achieved in our field operations which allowed costs to remain low despite the increased well count and production volumes.

***Production and Ad Valorem Tax Expense.*** Production and ad valorem taxes were $9.1 million for the three months ended September 30, 2016, an increase of $0.2 million, or 2%, from $9.0 million for the three months ended September 30, 2015. 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, among other factors, whereas production taxes are based upon current year commodity prices. During the three months ended September 30, 2016, our production taxes per BOE decreased by $0.65 as compared to the three months ended September 30, 2015, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2016, offset by an increase in ad valorem taxes primarily as a result of increased production.

***Depreciation, Depletion and Amortization.*** Depreciation, depletion and amortization expense decreased $7.6 million, or 15%, to $44.7 million for the three months ended September 30, 2016 from $52.4 million for the three months ended September 30, 2015.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

| | Three Months Ended September 30, | |
|---|---|---|
| | **2016** | **2015** |
| | **(in thousands, except BOE amounts)** | |
| Depletion of proved oil and natural gas properties | $ 44,340 | $ 51,996 |
| Depreciation of other property and equipment | 406 | 379 |
| Depreciation, depletion and amortization expense | $ 44,746 | $ 52,375 |
| Oil and natural gas properties depreciation, depletion and amortization per BOE | $ 10.73 | $ 16.58 |
| Total depreciation, depletion and amortization per BOE | $ 10.83 | $ 16.70 |

The decreases in depletion of proved oil and natural gas properties of $7.7 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 resulted primarily from the impairment of oil and gas properties recorded in the third quarter of 2016.

***Impairment of Oil and Gas Properties.*** During the three months ended September 30, 2016 and 2015, we recorded an impairment of oil and gas properties of $46.4 million and $273.7 million, respectively, as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves.

***General and Administrative Expense.*** General and administrative expense increased $2.4 million from $7.5 million for the three months ended September 30, 2015 to $9.9 million for the three months ended September 30, 2016. The increase was primarily due to an increase in non-cash equity compensation of $1.2 million and an increase in salaries and benefits of $2.0 million.

***Net Interest Expense.*** Net interest expense for the three months ended September 30, 2016 was $10.2 million as compared to $10.6 million for the three months ended September 30, 2015, a decrease of $0.4 million. This decrease was due primarily to the lower average level of outstanding borrowings under our credit facility during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015.

***Derivatives.*** We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2016, we had a cash loss on settlement of derivative instruments of $0.4 million as compared to a cash gain on settlement of derivative instruments of $35.5 million for the three months ended September 30, 2015. For the three months ended September 30, 2016, we had a positive change in the fair value of open derivative instruments of $2.4 million as compared to a negative change of $7.9 million during the three months ended September 30, 2015.

***Income Tax Expense (Benefit).*** We did not record an income tax expense or benefit for the three months ended September 30, 2016. We recorded an income tax benefit of $81.5 million for the three months ended September 30, 2015. Our effective tax rate was 34.3% for the three months ended September 30, 2015. During the three months ended September 30, 2016, we recorded a valuation allowance as management does not believe that it is more-likely-than-not that its net operating losses are realizable.

***Comparison of the Nine Months Ended September 30, 2016 and 2015***

***Oil, Natural Gas Liquids and Natural Gas Revenues.*** Our oil, natural gas liquids and natural gas revenues increased by approximately $9.7 million, or 3%, to $342.1 million for the nine months ended September 30, 2016 from $332.4 million for the nine months ended September 30, 2015. 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 8,466 BOE/d to 40,042 BOE/d during the nine months ended September 30, 2016 from 31,576 BOE/d during the nine months ended September 30, 2015. The total increase in revenue of approximately $9.7 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes partially offset by lower average sales prices for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 1,615,246 Bbls of oil, 397,412 Bbls of natural gas liquids and 2,032,009 Mcf of natural gas for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015.

The net dollar effect of the decreases in prices of approximately $76.4 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 $86.1 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 | $ (8.79) | 8,054,945 | $ (70,822) |
| Natural gas liquids | (0.17) | 1,657,189 | (282) |
| Natural gas | (0.70) | 7,556,147 | (5,289) |
| Total revenues due to change in price | | | $ (76,393) |

| | Change in production volumes(1) | Prior period Average Prices | Total net dollar effect of change |
|---|---|---|---|
| | | | (in thousands) |
| Effect of changes in production volumes: | | | |
| Oil | 1,615,246 | $ 46.87 | $ 75,687 |
| Natural gas liquids | 397,412 | 12.80 | 5,087 |
| Natural gas | 2,032,009 | 2.61 | 5,304 |
| Total revenues due to change in production volumes | | | 86,078 |
| Total change in revenues | | | $ 9,685 |

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

***Lease Operating Expense.*** Lease operating expense was $59.1 million ($5.38 per BOE) for the nine months ended September 30, 2016, a decrease of $6.0 million, or 9%, from $65.1 million ($7.55 per BOE) for the nine months ended September 30, 2015. The decrease is due to a reduction in service costs resulting from decreased commodity prices.

***Production and Ad Valorem Tax Expense.*** Production and ad valorem taxes were $25.2 million for both the nine months ended September 30, 2016 and 2015. 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, among other factors, whereas production taxes are based upon current year commodity prices. During the nine months ended September 30, 2016, our production taxes per BOE decreased by $0.60 as compared to the nine months ended September 30, 2015, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2016, offset by an increase in ad valorem taxes primarily as a result of increased production.

***Depreciation, Depletion and Amortization.*** Depreciation, depletion and amortization expense decreased $42.5 million, or 25%, to $126.7 million for the nine months ended September 30, 2016 from $169.1 million for the nine months ended September 30, 2015.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2016 | 2015 |
| | (in thousands, except BOE amounts) | |
| Depletion of proved oil and natural gas properties | $ 125,475 | $ 167,928 |
| Depreciation of other property and equipment | 1,211 | 1,220 |
| Depreciation, depletion and amortization expense | $ 126,686 | $ 169,148 |
| Oil and natural gas properties depreciation, depletion and amortization per BOE | $ 11.46 | $ 19.50 |
| Total depreciation, depletion and amortization per BOE | $ 11.55 | $ 19.62 |

The decreases in depletion of proved oil and natural gas properties of $42.5 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015 resulted primarily from the impairment of oil and gas properties recorded in the first three quarters of 2016.

***Impairment of Oil and Gas Properties.*** During the nine months ended September 30, 2016 and 2015, we recorded an impairment of oil and gas properties of $245.5 million and $597.2 million, respectively, as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves.

***General and Administrative Expense.*** General and administrative expense increased $9.0 million from $23.4 million for the nine months ended September 30, 2015 to $32.4 million for the nine months ended September 30, 2016. The increase was primarily due to an increase in non-cash equity compensation of $7.0 million and an increase in salaries and benefits of $3.1 million.

***Net Interest Expense.*** Net interest expense for the nine months ended September 30, 2016 was $30.3 million as compared to $31.4 million for the nine months ended September 30, 2015, a decrease of $1.2 million. This decrease was due primarily to the lower average level of outstanding borrowings under our credit facility during the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015.

***Derivatives.*** We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the nine months ended September 30, 2016 and 2015, we had a cash gain on settlement of derivative instruments of $4.2 million and $104.4 million, respectively. For the nine months ended September 30, 2016 and 2015, we had a negative change in the fair value of open derivative instruments of $12.9 million and $77.5 million, respectively.

***Income Tax Expense (Benefit).*** We had $0.4 million income tax expense for the nine months ended September 30, 2016 as compared to income tax benefit of $194.8 million for the nine months ended September 30, 2015. Our effective tax rate was 35.1% for the nine months ended September 30, 2015. During the nine months ended September 30, 2016, we recorded a valuation allowance as management does not believe that it is more-likely-than-not that its net operating losses are realizable.

**Liquidity and Capital Resources**

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

***Liquidity and Cash Flow***

Our cash flows for the nine months ended September 30, 2016 and 2015 are presented below:

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2016** | **2015** |
| | **(in thousands)** | |
| Net cash provided by operating activities | $ 226,346 | $ 339,604 |
| Net cash used in investing activities | (982,040) | (787,864) |
| Net cash provided by financing activities | 902,848 | 461,904 |
| Net increase in cash | $ 147,154 | $ 13,644 |

***Operating Activities***

Net cash provided by operating activities was $226.3 million for the nine months ended September 30, 2016 as compared to $339.6 million for the nine months ended September 30, 2015. The decrease in operating cash flows is primarily due a reduction in the amounts received from the settlement of derivative contracts during the nine months ended September 30, 2016.

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. Net cash used in investing activities was $982.0 million and $787.9 million during the nine months ended September 30, 2016 and 2015, respectively.

During the nine months ended September 30, 2016, we spent (a) $243.4 million on capital expenditures in conjunction with our development program, in which we drilled 48 gross (38 net) horizontal wells, completed 39 gross (34 net) horizontal wells and participated in the drilling of 12 gross (four net) non-operated wells in the Permian Basin, (b) $591.8 million on leasehold acquisitions, (c) $137.8 million on royalty interest acquisitions and (d) $9.8 million for the purchase of other property and equipment.

During the nine months ended September 30, 2015, we spent $326.5 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 47 gross (40 net) horizontal wells and three gross (two net) vertical wells and participated in the drilling of 12 gross (five net) non-operated wells in the Permian Basin. We spent an additional $425.5 million on leasehold costs and $1.0 million for the purchase of other property and equipment. In June 2015, we completed acquisitions of oil and natural gas leasehold and mineral interests in Howard County, Texas, in the Permian Basin from unrelated third party sellers for an aggregate purchase price of approximately $425.5 million. Also, during the first nine months of 2015, we completed several smaller acquisitions of oil and natural gas leasehold and mineral interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $32.3 million.

Our investing activities for the nine months ended September 30, 2016 and 2015 are summarized in the following table:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2016 | 2015 |
| | (in thousands) | |
| Drilling, completion and infrastructure | $ (243,434) | $ (326,469) |
| Acquisition of leasehold interests | (591,785) | (425,507) |
| Acquisition of royalty interests | (137,782) | (32,291) |
| Purchase of other property and equipment | (9,805) | (992) |
| Proceeds from sale of property and equipment | 1,566 | 97 |
| Equity investments | (800) | (2,702) |
| Net cash used in investing activities | $ (982,040) | $ (787,864) |

***Financing Activities***

Net cash provided by financing activities for the nine months ended September 30, 2016 and 2015 was $902.8 million and $461.9 million, respectively. During the nine months ended September 30, 2016, the amount provided by financing activities was primarily attributable to proceeds from our January and July 2016 equity offerings of $900.7 million partially offset by repayments of net borrowings of $9.0 million under our credit facility. The 2015 amount provided by financing activities was primarily attributable to the proceeds from our January, May and August 2015 equity offerings of $650.7 million partially offset by repayments of net borrowings of $184.5 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, November 13, 2014 and June 21, 2016, with a syndicate 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 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 September 30, 2016, the borrowing base was set at $700.0 million, although we had elected a commitment amount of $500.0 million. As of September 30, 2016, we had no outstanding borrowings and $500.0 million available for future borrowings under this facility. As of September 30, 2016, the loan was guaranteed by us, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any of our future restricted subsidiaries. The credit agreement is also secured by substantially all of our assets and the assets of Diamondback O&G LLC and the guarantors. In connection with our spring 2016 redetermination, our borrowing base was reduced to $700.0 million due to a decline in pricing. In connection with our fall 2016 redetermination, the agent lender under the credit agreement has recommended that our borrowing base be increased to $1.0 billion. Notwithstanding such adjustment, we have elected to continue to limit the lenders' aggregate commitment to $500.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% 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 0.500% 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 repaid (a) to the extent that 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 $750.0 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of September 30, 2016, we had $450.0 million in aggregate principal amount of senior notes outstanding. See also "–4.75% Senior Notes due 2024" and "–Tender Offer and Redemption–Existing 2021 Senior Notes."

As of September 30, 2016, 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.

***Viper's Facility-Wells Fargo Bank***

On July 8, 2014, Viper entered into a secured revolving credit agreement with Wells Fargo Bank, 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 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. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. On November 13, 2015, the borrowing base was increased from $175.0 million to $200.0 million. In connection with Viper's spring 2016 redetermination, Viper's borrowing base was reduced to $175.0 million due to a decline in pricing. On August 5, 2016, Viper repaid $78.0 million of its outstanding borrowings with a portion of the proceeds from its August 2016 public offering of common units and, as of September 30, 2016, Viper had $54.5 million outstanding under its credit agreement with a weighted average interest rate of 2.28%. In connection with Viper's fall 2016 redetermination, the agent lender under the credit agreement has recommended that Viper's borrowing base be increased to $275.0 million.

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 0.5% 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 repaid (a) to the extent that 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 Viper and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, purchases of margin stock, 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 $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under Viper’s revolving credit facility upon the occurrence and during the continuance of any event of default. Viper’s 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.

***4.75% Senior Notes due 2024***

On October 28, 2016, we issued $500.0 million in aggregate principal amount of our 4.75% Senior Notes due 2024. The 2024 Senior Notes bear interest at a rate of 4.75% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017 and will mature on November 1, 2024. As of the closing date, the 2024 Senior Notes are fully and unconditionally guaranteed by Diamondback O&G LLC and Diamondback E&P LLC and will also be guaranteed by any of our future restricted subsidiary.

***Tender Offer and Redemption-Existing 2021 Senior Notes***

On October 21, 2016, we commenced a cash tender offer to purchase any and all of our 2021 Senior Notes, which tender offer expired on October 27, 2016 and settled on October 28, 2016. Holders of the 2021 Senior Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2021 Senior Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,059.69 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $330.1 million principal amount of the 2021 Senior Notes was validly tendered in the tender offer. The remaining 2021 Senior Notes that were not tendered in the tender offer were redeemed by us. The redemption payment included approximately $119.9 million of outstanding principal at a redemption price of 105.719% of the principal amount of the redeemed 2021 Senior Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 28, 2016, the indenture governing the 2021 Senior Notes was fully satisfied and discharged. The cash tender offer for the 2021 Senior Notes and redemption of the remaining 2021 Senior Notes were funded with a portion of the net proceeds from our offering of the 2024 Senior Notes discussed in more detail above.

***Capital Requirements and Sources of Liquidity***

Our board of directors initially approved a 2016 capital budget for drilling and infrastructure of $250.0 million to $375.0 million, representing a decrease of 9% over our 2015 capital budget. In July 2016, we increased our expected 2016 capital budget for drilling, completion and infrastructure to a range of $350.0 million to $425.0 million due to improvements in commodity prices. We estimate that, of these expenditures, approximately:

- $305.0 million to $360.0 million will be spent on drilling and completing 65 to 70 gross (50 to 63 net) operated horizontal wells focused in the Permian Basin, an increase of 30% from the midpoint of the prior range of the 30 to 70 gross operated horizontal wells;

- $30.0 million to $40.0 million will be spent on infrastructure; and

- $15.0 million to $25.0 million will be spent on non-operated activity and other expenditures.

During the nine months ended September 30, 2016, our aggregate capital expenditures for our development program were $243.4 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2016, we spent approximately $591.8 million on acquisitions of leasehold interests.

The amount and timing of these capital expenditures are 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. With recent improvement in oil prices, we are currently operating five horizontal rigs and two completion crews. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Based upon current oil and natural gas price and production expectations for 2016, we believe that our cash flow from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2016. 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 2016 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. If there is further decline in commodity prices, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

**Contractual Obligations**

Except as discussed in Note 15 of the Notes to the Consolidated Financial Statements of this report, 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, 2015.

**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, 2015.

**Off-Balance Sheet Arrangements**

We had no off-balance sheet arrangements as of September 30, 2016. Please read Note 15 included in Notes to the Combined Consolidated Financial Statements set forth in Part I, Item 1 of this report, 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, including basis swaps, 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 NYMEX West Texas Intermediate pricing.

At September 30, 2016, we had a net liability derivative position of $8.2 million related to our price swap derivatives, as compared to a net asset derivative position of $4.6 million as of December 31, 2015 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of September 30, 2016, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $15.9 million, an increase of $7.6 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position to $0.6 million, a decrease of $7.6 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 $33.0 million at September 30, 2016) and receivables from the sale of our oil and natural gas production (approximately $52.5 million at September 30, 2016).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the nine months ended September 30, 2016, three purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (50%); Enterprise Crude Oil LLC (13%); and Koch Supply & Trading LP (12%). For the nine months ended September 30, 2015, two purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (60%); and Enterprise Crude Oil LLC (14%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At September 30, 2016, we had two customers that represented approximately 75% of our total joint operations receivables. At December 31, 2015, we had five customers that represented approximately 73% of our total joint operations receivables.

***Interest Rate Risk***

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% 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.

As of September 30, 2016, we had no borrowings outstanding under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 1.92% on January 19, 2016, the last day on which borrowings were outstanding under such facility. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.1 million based on the $11.0 million outstanding in the aggregate under our revolving credit facility as of such date.

## 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 September 30, 2016, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of September 30, 2016, our disclosure controls and procedures are effective.

### Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2016 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 materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2015. 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, 2015.

**ITEM 6. EXHIBITS**

**EXHIBIT INDEX**

| Exhibit Number | Description |
|---|---|
| 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 October 28, 2016, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Diamondback Energy, Inc.'s 4.750 % Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K , File No. 001-35700, filed by the Company with the SEC on November 2, 2016). |
| 4.5 | Registration Rights Agreement, dated as of October 28, 2016, among Diamondback Energy, Inc., the guarantors party thereto and J.P. Morgan Securities LLC (incorporated by reference to Exhibit 4.2 to the Form 8-K , File No. 001-35700, filed by the Company with the SEC on November 2, 2016). |
| 31.1* | Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended. |
| 31.2* | Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended. |
| 32.1** | Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code. |
| 32.2** | Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code. |
| 101.INS* | XBRL Instance Document. |
| 101.SCH* | XBRL Taxonomy Extension Schema Document. |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase. |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase Document. |
| 101.LAB* | XBRL Taxonomy Extension Labels Linkbase Document. |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase Document. |

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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.

**SIGNATURES**

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

| | | |
|---|---|---|
| | | DIAMONDBACK ENERGY, INC. |
| Date: | November 8, 2016 | /s/ Travis D. Stice |
| | | Travis D. Stice<br>Chief Executive Officer<br>(Principal Executive Officer) |
| Date: | November 8, 2016 | /s/ Teresa L. Dick |
| | | Teresa L. Dick<br>Chief Financial Officer<br>(Principal Financial and Accounting Officer) |

**EXHIBIT 31.1**

**CERTIFICATION**

I, Travis D. Stice, certify that:

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

Date: November 8, 2016

/s/ Travis D. Stice

Travis D. Stice
Chief Executive Officer

**EXHIBIT 31.2**

**CERTIFICATION**

I, Teresa L. Dick, certify that:

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

Date: November 8, 2016

/s/ Teresa L. Dick

Teresa L. Dick
Chief Financial Officer

**EXHIBIT 32.1**

**CERTIFICATION OF PERIOD REPORT**

In connection with the Quarterly Report on Form 10-Q of Diamondback Energy, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Travis D. Stice, Chief Executive Officer of Diamondback Energy, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

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

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

| | |
|---|---|
| Date: November 8, 2016 | /s/ Travis D. Stice |
| | Travis D. Stice |
| | Chief Executive Officer |

**EXHIBIT 32.2**

## CERTIFICATION OF PERIOD REPORT

In connection with the Quarterly Report on Form 10-Q of Diamondback Energy, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Teresa L. Dick, Chief Financial Officer of Diamondback Energy, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

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

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

Date: November 8, 2016

/s/ Teresa L. Dick

Teresa L. Dick
Chief Financial Officer