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

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED March 31, 2018

OR

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

Commission File Number 001-35700

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check One):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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 May 4, 2018, 98,611,408 shares of the registrant’s common stock were outstanding.

DIAMONDBACK ENERGY, INC.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2018

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
British Thermal Unit or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
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.
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.
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.

Company	Diamondback Energy, Inc., a Delaware corporation.
Equity Plan	The Company's Equity Incentive Plan.
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.
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.
2024 Senior Notes	The Company's 4.750% senior unsecured notes due 2024 in the aggregate principal amount of $500 million.
2025 Senior Notes	The Company's 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $500 million.
Senior Notes	The 2024 Senior Notes and the 2025 Senior Notes.
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, 2017 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;
- 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)

	March 31, 2018	December 31, 2017
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 72,487	$ 112,446
Accounts receivable:		
Joint interest and other	71,017	73,038
Oil and natural gas sales	165,263	158,575
Inventories	8,963	9,108
Derivative instruments	—	531
Prepaid expenses and other	6,737	4,903
Total current assets	324,467	358,601
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($4,204,745 and $4,105,865 excluded from amortization at March 31, 2018 and December 31, 2017, respectively)	9,648,825	9,232,694
Midstream assets	295,161	191,519
Other property, equipment and land	82,095	80,776
Accumulated depletion, depreciation, amortization and impairment	(2,274,909)	(2,161,372)
Net property and equipment	7,751,172	7,343,617
Funds held in escrow	10	6,304
Investment in real estate, net	109,103	—
Other assets	40,136	62,463
Total assets	$ 8,224,888	$ 7,770,985
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable-trade	$ 63,129	$ 94,590
Accrued capital expenditures	262,242	221,256
Other accrued liabilities	100,557	92,512
Revenues and royalties payable	82,055	68,703
Derivative instruments	99,685	100,367
Total current liabilities	607,668	577,428
Long-term debt	1,701,912	1,477,347
Derivative instruments	6,492	6,303
Asset retirement obligations	21,258	20,122
Deferred income taxes	152,369	108,048
Other long term liabilities	7	—
Total liabilities	2,489,706	2,189,248
Commitments and contingencies (Note 16)		
Stockholders’ equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 98,610,608 issued and outstanding at March 31, 2018; 98,167,289 issued and outstanding at December 31, 2017	986	982
Additional paid-in capital	5,299,811	5,291,011
Accumulated deficit	116,286	(37,133)
Total Diamondback Energy, Inc. stockholders’ equity	5,417,083	5,254,860
Non-controlling interest	318,099	326,877
Total equity	5,735,182	5,581,737
Total liabilities and equity	$ 8,224,888	$ 7,770,985

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(In thousands, except per share amounts)	
Revenues:		
Oil sales	$ 419,268	$ 207,074
Natural gas sales	14,378	9,922
Natural gas liquid sales	33,113	15,502
Lease bonus	—	1,602
Midstream services	11,395	1,130
Other operating income	2,041	—
Total revenues	480,195	235,230
Costs and expenses:		
Lease operating expenses	37,345	26,626
Production and ad valorem taxes	27,304	15,725
Gathering and transportation	4,285	2,619
Midstream services	11,189	854
Depreciation, depletion and amortization	115,216	58,929
General and administrative expenses (including non-cash equity-based compensation, net of capitalized amounts, of $7,451 and $7,063 for the three months ended March 31, 2018 and 2017, respectively)	16,325	13,744
Asset retirement obligation accretion	355	323
Other operating expense	530	—
Total costs and expenses	212,549	118,820
Income from operations	267,646	116,410
Other income (expense):		
Interest expense, net	(13,701)	(12,225)
Other income, net	2,736	1,145
Gain (loss) on derivative instruments, net	(32,345)	37,701
Gain on revaluation of investment	899	—
Total other income (expense), net	(42,411)	26,621
Income before income taxes	225,235	143,031
Provision for income taxes	47,081	1,957
Net income	178,154	141,074
Net income attributable to non-controlling interest	15,342	4,801
Net income attributable to Diamondback Energy, Inc.	$ 162,812	$ 136,273
Earnings per common share:		
Basic	$ 1.65	$ 1.46
Diluted	$ 1.65	$ 1.46
Weighted average common shares outstanding:		
Basic	98,555	93,161
Diluted	98,769	93,364
Dividends declared per share	$ 0.125	$ —

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, 2016	90,144	$ 901	$ 4,215,955	$ (519,394)	$ 320,830	$ 4,018,292
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	147,523	147,523
Unit-based compensation		—	—	—	819	819
Stock-based compensation		—	8,587	—	—	8,587
Distribution to non-controlling interest		—	—	—	(6,482)	(6,482)
Common shares issued in public offering, net of offering costs		—	14	—	—	14
Common shares issued for acquisition	7,686	77	809,096	—	—	809,173
Exercise of stock options and vesting of restricted stock units	298	3	355	—	—	358
Net income		—	—	136,273	4,801	141,074
Balance March 31, 2017	98,128	$ 981	$ 5,034,007	$ (383,121)	$ 467,491	$ 5,119,358
Balance December 31, 2017	98,167	$ 982	$ 5,291,011	$ (37,133)	$ 326,877	$ 5,581,737
Impact of adoption of ASU 2016-01, net of tax		—	—	(9,393)	(6,671)	(16,064)
Unit-based compensation		—	—	—	1,288	1,288
Stock-based compensation		—	8,804	—	—	8,804
Distribution to non-controlling interest		—	—	—	(18,737)	(18,737)
Exercise of stock options and vesting of restricted stock units	443	4	(4)	—	—	—
Net income		—	—	162,812	15,342	178,154
Balance March 31, 2018	98,610	$ 986	$ 5,299,811	$ 116,286	$ 318,099	$ 5,735,182

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 178,154	$ 141,074
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	46,908	1,425
Asset retirement obligation accretion	355	323
Depreciation, depletion and amortization	115,216	58,929
Amortization of debt issuance costs	748	852
Change in fair value of derivative instruments	38	(39,375)
Income from equity investment	(2,167)	(3)
Gain on revaluation of investment	(899)	—
Equity-based compensation expense	7,451	7,063
Gain on sale of assets, net	—	(12)
Changes in operating assets and liabilities:		
Accounts receivable	6,322	(20,104)
Accounts receivable-related party	—	199
Restricted cash	—	500
Inventories	(12,778)	(1,044)
Prepaid expenses and other	(6,765)	(19,894)
Accounts payable and accrued liabilities	(18,280)	10,281
Accounts payable and accrued liabilities-related party	—	(2)
Accrued interest	11,413	10,313
Income tax payable	359	—
Revenues and royalties payable	13,352	25,402
Net cash provided by operating activities	339,427	175,927
Cash flows from investing activities:		
Additions to oil and natural gas properties	(280,015)	(116,174)
Additions to midstream assets	(38,395)	(59)
Purchase of other property, equipment and land	(1,947)	(11,918)
Acquisition of leasehold interests	(16,011)	(1,760,810)
Acquisition of mineral interests	(150,013)	(8,579)
Acquisition of midstream assets	—	(48,329)
Proceeds from sale of assets	125	1,238
Investment in real estate	(109,664)	—
Funds held in escrow	10,989	119,340
Equity investments	—	(188)
Net cash used in investing activities	(584,931)	(1,825,479)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	224,000	—
Repayment under credit facility	(308,000)	(120,500)
Proceeds from senior notes	312,000	—
Debt issuance costs	(3,718)	(418)
Public offering costs	—	(265)
Proceeds from public offerings	—	147,725
Proceeds from exercise of stock options	—	358
Distributions to non-controlling interest	(18,737)	(6,482)
Net cash provided by financing activities	205,545	20,418

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

	Three Months Ended March 31,	
	2018	2017
Net decrease in cash and cash equivalents	(39,959)	(1,629,134)
Cash and cash equivalents at beginning of period	112,446	1,666,574
Cash and cash equivalents at end of period	$ 72,487	$ 37,440
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 4,305	$ 1,118
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ 40,986	$ 34,460
Capitalized stock-based compensation	$ 2,641	$ 2,343
Common stock issued for oil and natural gas properties	$ —	$ 809,173
Asset retirement obligations acquired	$ 12	$ 2,129

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 March 31, 2018, 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, Rattler Midstream LLC (formerly known as White Fang Energy LLC), a Delaware limited liability company, and Tall City Towers LLC, a Delaware limited liability company. The consolidated subsidiaries include these 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 March 31, 2018, the Company owned approximately 64% of the common units of the Partnership. 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, 2017, 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 assumed, equity-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Investments

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over the limited partnership's operating and financial policies. This interest was acquired during the year ended December 31, 2014 and is accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption. For the three months ended March 31, 2018, the Partnership recorded a gain of $0.9 million which then increased the Partnership's investment balance to $16.0 million, which is included in other assets in the accompanying consolidated balance sheets.

New Accounting Pronouncements

Recently Adopted Pronouncements

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

In 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. The Company adopted this update effective January 1, 2018 using the retrospective transition method. Adoption of this standard did not have an effect on the presentation on the Statement of Cash Flows.

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

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

Accounting Pronouncements Not Yet Adopted

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

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

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

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Impact of Accounting Standards Codification Topic 606 Adoption

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

Revenue from Contracts with Customers

Sales of oil, natural gas and natural gas liquids are recognized at the point control of the product is transferred to the customer. Virtually all of the pricing provisions in the Company’s contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies.

Oil sales

The Company’s oil sales contracts are generally structured where it delivers oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company or a third party transports the product to the delivery point and receives a specified index price from the purchaser with no deduction. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company’s consolidated statements of operations.

Natural gas and natural gas liquids sales

Under the Company's natural gas processing contracts, it delivers natural gas to a midstream processing entity at the wellhead, battery facilities or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of natural gas liquids and residue gas. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation, gathering, processing, treating and compression fees presented as an expense in its consolidated statements of operations.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or natural gas liquids in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing, treating and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing, treating and compression expense in its consolidated statements of operations.

Midstream Revenue

Substantially all revenues from gathering, compression, water handling, disposal and treatment operations are derived from intersegment transactions for services Rattler Midstream LLC ("Rattler") provides to exploration and production operations. The portion of such fees shown in the Company's consolidated financial statements represent amounts charged to interest owners in the Company's operated wells, as well as fees charged to other third parties for water handling and treatment services provided by Rattler or usage of Rattler's gathering and compression systems. For gathering and compression revenue, Rattler satisfies its performance obligations and recognizes revenue when low pressure volumes are delivered to a specified delivery point. Revenue is recognized based on the per MMbtu gathering fee or a per barrel gathering fee charged by Rattler in accordance with the gathering and compression agreement. For water handling and treatment revenue, Rattler satisfies its performance obligations and recognizes revenue when the fresh water volumes have been delivered to the fracwater meter for a specified well pad and the wastewater volumes have been metered downstream of the Company's facilities. For services contracted through third party providers, Rattler's performance obligation is satisfied when the service performed by the third party provider has been completed. Revenue is recognized based on the per barrel fresh water delivery or a wastewater gathering and disposal fee charged by Rattler in accordance with the water services agreement.

Transaction price allocated to remaining performance obligations

The Company's product sales contracts do not originate until production occurs and, therefore, are not considered to exist beyond each days' production. Therefore, there are no remaining performance obligation under any of our product sales contracts.

Contract balances

Under the Company's product sales contracts, it has the right to invoice its customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under Accounting Standards Codification 606.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and natural gas liquids sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the three months ended March 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the revenue related to expected sales volumes and prices for those properties are estimated and recorded.

4. ACQUISITIONS

On January 31, 2018, Tall City Towers LLC, a subsidiary of the Company, completed its acquisition of the Fasken Center office buildings in Midland, TX where the Company's corporate offices are located for a net purchase price of $109.7 million.

On February 28, 2017, the Company completed its acquisition of certain oil and natural gas properties, midstream assets and other related assets in the Delaware Basin for an aggregate purchase price consisting of $1.74 billion in cash and 7.69 million shares of the Company's common stock, of which approximately 1.15 million shares were placed in an indemnity escrow. This transaction includes the acquisition of (i) approximately 100,306 gross (80,339 net) acres primarily in Pecos and Reeves counties for approximately $2.5 billion and (ii) midstream assets for approximately $47.6 million. The Company used the net proceeds from its December 2016 equity offering, net proceeds from its December 2016 debt offering, cash on hand and other financing sources to fund the cash portion of the purchase price for this acquisition.

The following represents the fair value of the assets and liabilities assumed on the acquisition date. The aggregate consideration transferred was $2.5 billion, resulting in no goodwill or bargain purchase gain.

		(in thousands)
Proved oil and natural gas properties	$	386,308
Unevaluated oil and natural gas properties		2,122,597
Midstream assets		47,432
Prepaid capital costs		3,460
Oil inventory		839
Equipment		163
Revenues and royalties payable		(9,650)
Asset retirement obligations		(1,550)
Total fair value of net assets	$	2,549,599

The Company included in its consolidated statements of operations revenues of $12.2 million and direct operating expenses of $2.7 million for the period from February 28, 2017 to March 31, 2017 due to the acquisition.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the three months ended March 31, 2017 have been prepared to give effect to the February 28, 2017 acquisition as if it had occurred on January 1, 2016. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2016.

The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended March 31, 2017	
	(in thousands, except per share amounts)	
Revenues	$	258,159
Income from operations		133,162
Net income		150,615
Basic earnings per common share		1.62
Diluted earnings per common share		1.61

5. 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 and the Eagle Ford Shale. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of March 31, 2018, the Company owned approximately 64% 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. For both the three months ended March 31, 2018 and 2017, the General Partner allocated $0.6 million 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 12—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 9—Debt for a description of this credit facility.

6. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	March 31, 2018	December 31, 2017
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$ 5,444,080	$ 5,126,829
Not subject to depletion	4,204,745	4,105,865
Gross oil and natural gas properties	9,648,825	9,232,694
Accumulated depletion	(1,114,399)	(1,009,893)
Accumulated impairment	(1,143,498)	(1,143,498)
Oil and natural gas properties, net	7,390,928	7,079,303
Midstream assets	295,161	191,519
Other property, equipment and land	82,095	80,776
Accumulated depreciation	(17,012)	(7,981)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 7,751,172	$ 7,343,617

Balance of costs not subject to depletion:	
Incurred in 2018	$ 159,352
Incurred in 2017	2,746,718
Incurred in 2016	721,400
Incurred in 2015	283,673
Incurred in 2014	293,602
Total not subject to depletion	$ 4,204,745

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. Costs, including related employee costs, associated with production and operation of the properties are charged to expense as incurred. All other internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. Capitalized internal costs were approximately $7.0 million and $5.1 million for the three months ended March 31, 2018 and 2017, 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. Acquisition costs not currently being amortized are primarily related to unproved acreage that the Company plans to prove up through drilling. The Company has no plans to let any acreage expire. 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 natural 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.

At March 31, 2018, there was $48.5 million in exploration costs and development costs and $28.8 million in capitalized interest that was not subject to depletion. At December 31, 2017, there were $26.0 million in exploration costs and development costs and $22.1 million in capitalized interest that was not subject to depletion.

7. ASSET RETIREMENT OBLIGATIONS

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

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Asset retirement obligations, beginning of period	$ 21,285	$ 17,422
Additional liabilities incurred	765	741
Liabilities acquired	12	2,129
Liabilities settled	(775)	(102)
Accretion expense	355	323
Revisions in estimated liabilities	10	(2)
Asset retirement obligations, end of period	21,652	20,511
Less current portion	394	1,572
Asset retirement obligations - long-term	$ 21,258	$ 18,939

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. The current portion of the asset retirement obligation liability is included in other accrued liabilities in the Company's consolidated balance sheets.

8. EQUITY METHOD INVESTMENTS

In October 2014, the Company obtained 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. During the three months ended March 31, 2018, the Company recorded $2.2 million, which is the Company's share of HMW Fluid Management LLC's net income, bringing its total investment to $9.4 million at March 31, 2018. During the three months ended March 31, 2017, the Company invested $0.2 million in this entity and recorded $3,000, which is the Company's share of HMW Fluid Management LLC's net income, bringing its total investment to $6.5 million at March 31, 2017. 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.

9. DEBT

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

	March 31, 2018	December 31, 2017
	(in thousands)	
4.750 % Senior Notes due 2024	$ 500,000	$ 500,000
5.375 % Senior Notes due 2025	800,000	500,000
Unamortized debt issuance costs	(16,312)	(13,153)
Unamortized premium costs	11,724	—
Revolving credit facility	166,000	397,000
Partnership revolving credit facility	240,500	93,500
Total long-term debt	$ 1,701,912	$ 1,477,347

2024 Senior Notes

On October 28, 2016, the Company issued $500.0 million in aggregate principal amount of 4.750% Senior Notes due 2024 (the “2024 Senior Notes”). The 2024 Senior Notes bear interest at a rate of 4.750% 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. All of the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the 2024 Senior Notes; provided, however, that the 2024 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

The 2024 Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented (the “2024 Indenture”). The 2024 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 capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted 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 natural gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries.

The Company may on any one or more occasions redeem some or all of the 2024 Senior Notes at any time on or after November 1, 2019 at the redemption prices (expressed as percentages of principal amount) of 103.563% for the 12-month period beginning on November 1, 2019, 102.375% for the 12-month period beginning on November 1, 2020, 101.188% for the 12-month period beginning on November 1, 2021 and 100.000% beginning on November 1, 2022 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to November 1, 2019, the Company may on any one or more occasions redeem all or a portion of the 2024 Senior Notes at a price equal to 100% of the principal amount of the 2024 Senior Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to November 1, 2019, the Company may on any one or more occasions redeem the 2024 Senior Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2024 Senior Notes issued prior to such date at a redemption price of 104.750%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

2025 Senior Notes

On December 20, 2016, the Company issued $500.0 million in aggregate principal amount of 5.375% Senior Notes due 2025 (the “2025 Senior Notes”). The 2025 Senior Notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year, commencing on May 31, 2017 and will mature on May 31, 2025. All of the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the 2025 Senior Notes, provided, however, that the 2025 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

On January 29, 2018, the Company issued $300.0 million aggregate principal amount of new 5.375% Senior Notes due 2025 (the "New 2025 Notes") as additional notes under, and subject to the terms of, the 2025 Indenture. The New 2025 Notes were issued in a transaction exempt from the registration requirements under the Securities Act. The Company received approximately $308.4 million in net proceeds, after deducting the initial purchaser's discount and its estimated offering expenses, but disregarding accrued interest, from the issuance of the New 2025 Notes. The Company used the net proceeds from the issuance of the New 2025 Notes to repay a portion of the outstanding borrowings under its revolving credit facility.

The 2025 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 capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of the Company's assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries.

The Company may on any one or more occasions redeem some or all of the 2025 Senior Notes (including the New 2025 Notes) at any time on or after May 31, 2020 at the redemption prices (expressed as percentages of principal amount) of 104.031% for the 12-month period beginning on May 31, 2020, 102.688% for the 12-month period beginning on May 31, 2021, 101.344% for the 12-month period beginning on May 31, 2022 and 100.000% beginning on May 31, 2023 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to May 31, 2020, the Company may on any one or more occasions redeem all or a portion of the 2025 Senior Notes (including the New 2025 Notes) at a price equal to 100% of the principal amount of the 2025 Senior Notes (including the New 2025 Notes) plus a "make-whole" premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 31, 2020, the Company may on any one or more occasions redeem the 2025 Senior Notes (including the New 2025 Notes) in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2025 Senior Notes (including the New 2025 Notes) issued prior to such date at a redemption price of 105.375%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

The Company's Credit Facility

The Company and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014, November 13, 2014, June 21, 2016, December 15, 2016 and November 28, 2017, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on the Company's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, the Company may request up to two additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2018, the borrowing base was set at $1.8 billion, the Company had elected a commitment amount of $1.0 billion and the Company had $166.0 million of outstanding borrowings under the revolving credit facility and $834.0 million available for future borrowings under its revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement. As of December 31, 2017, the credit agreement is guaranteed by the Company, Diamondback E&P LLC and Rattler Midstream LLC (formerly known as White Fang Energy LLC) and will also be guaranteed by any of the Company's future subsidiaries that are classified as restricted subsidiaries under the credit agreement. The credit agreement is also secured by substantially all of the assets of the Company, Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Company that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5%, and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.25% in the case of the alternate base rate and from 1.25% to 2.25% in the case of LIBOR, each of which applicable margin rates is increased by 0.25% per annum if the total debt to EBITDAX ratio is greater than 3.0 to 1.0. The applicable margin depends on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. 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 commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022.

The 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, as amended in November 2017, allows for the issuance of unsecured debt in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.

As of March 31, 2018 and December 31, 2017, 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 administrative agent, and Wells Fargo Securities, as sole book runner and lead arranger. The credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on the Partnership’s oil and natural gas reserves and other factors (the “borrowing base”) of $400.0 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2018, the borrowing base was set at $400.0 million, and the Partnership had $240.5 million of outstanding borrowings and $159.5 million available for future borrowings under its revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Partnership that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. 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 commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (i) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (ii) 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 (iii) at the maturity date of November 1, 2022. The loan is secured by substantially all of the Partnership and its subsidiary's assets.

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 $400.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

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.

10. CAPITAL STOCK AND EARNINGS PER SHARE

Diamondback completed no equity offerings during the three months ended March 31, 2018 and March 31, 2017.

Partnership Equity Offerings

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

Earnings Per Share

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

A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(in thousands, except per share amounts)	
Net income attributable to common stock	$ 162,812	$ 136,273
Weighted average common shares outstanding		
Basic weighted average common units outstanding	98,555	93,161
Effect of dilutive securities:		
Potential common shares issuable	214	203
Diluted weighted average common shares outstanding	98,769	93,364
Basic net income attributable to common stock	$ 1.65	$ 1.46
Diluted net income attributable to common stock	$ 1.65	$ 1.46

For the three months ended March 31, 2018 and 2017, there were zero shares and 14 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.

11. EQUITY-BASED COMPENSATION

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(in thousands)	
General and administrative expenses	$ 7,451	$ 7,063
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	2,641	2,343

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the Equity Plan during the three months ended March 31, 2018.

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	243,577	$ 90.88
Granted	73,763	$ 113.78
Vested	(106,691)	$ 86.30
Forfeited	(1,427)	$ 94.43
Unvested at March 31, 2018	209,222	$ 101.26

The aggregate fair value of restricted stock units that vested during the three months ended March 31, 2018 and 2017 was $9.2 million and $11.3 million, respectively. As of March 31, 2018, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $17.3 million. Such cost is expected to be recognized over a weighted-average period of 1.8 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 2018, eligible employees received performance restricted stock unit awards totaling 117,423 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, 2018 to December 31, 2020 and cliff vest at December 31, 2020.

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 2018 awards.

	2018
	Three-Year Performance Period
Grant-date fair value	$ 170.45
Risk-free rate	1.99%
Company volatility	35.90%

The following table presents the Company's performance restricted stock units activity under the Equity Plan for the three months ended March 31, 2018.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	202,326	$ 139.83
Granted	285,737	$ 130.96
Vested	(168,314)	$ 103.41
Unvested at March 31, 2018[(1)]	319,749	$ 151.08

(1) A maximum of 639,498 units could be awarded based upon the Company's final TSR ranking.

As of March 31, 2018, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $34.8 million. Such cost is expected to be recognized over a weighted-average period of 2.8 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 three months ended March 31, 2018.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	105,439	$ 17.10
Granted	101,403	$ 23.18
Vested	(39,147)	$ 22.30
Unvested at March 31, 2018	167,695	$ 19.56

The aggregate fair value of phantom units that vested during the three months ended March 31, 2018 was $0.9 million. As of March 31, 2018, the unrecognized compensation cost related to unvested phantom units was $2.4 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

12. RELATED PARTY TRANSACTIONS

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 had 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. The Partnership did not incur any costs during the three months ended March 31, 2018 or March 31, 2017 under the Viper Advisory Services Agreement.

Lease Bonus - The Partnership

During the three months ended March 31, 2018, the Company did not pay the Partnership any lease bonus payments. During the three months ended March 31, 2017, the Company paid the Partnership $1,500 in lease bonus payments to extend the term of one lease, reflecting an average bonus of $400 per acre.

13. INCOME TAXES

The Company’s effective income tax rates were 20.9% and 1.4% for the three months ended March 31, 2018 and 2017, respectively. Total income tax expense for the three months ended March 31, 2018 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to current and deferred state income taxes, net income attributable to the non-controlling interest and the impact of permanent differences between book and taxable income. The Company recorded a discrete income tax benefit of approximately $0.2 million related to equity-based compensation for the three months ended March 31, 2018. Total income tax expense for the three months ended March 31, 2017 differed from amounts computed by applying the federal statutory rate to pre-tax income primarily due to state income taxes

The Tax Cuts and Jobs Act, a historic reform of the U.S. federal income tax statutes, was enacted on December 22, 2017. As of the completion of the Company’s financial statements for the year ended December 31, 2017, the Company had substantially completed its accounting for the effects of the enactment of the Tax Cuts and Jobs Act and, with respect to those items for which the Company’s accounting was not complete, the Company made reasonable estimates of the effects on its deferred tax balances. At March 31, 2018, the Company has not made an adjustment to the provisional estimates recorded for the year ended December 31, 2017. The Company has considered in its estimated annual effective tax rate for 2018 the impact of the statutory changes enacted by the Tax Cuts and Jobs Act, including reasonable estimates of those provisions effective for the 2018 tax year.

As discussed further in Note 17, on March 29, 2018, the Partnership announced that the Board of Directors of its General Partner had unanimously approved a change of the Partnership’s federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. The transactions to be undertaken in connection with the change in the Partnership's tax status are not expected to be taxable to the Company.

14. 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, fixed price basis swap contracts and three-way costless collars with corresponding put, short put and call options to reduce price volatility associated with certain of its oil and natural gas sales. With respect to the Company's fixed price swap contracts and fixed price basis swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap or basis 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 or basis price. The Company has fixed price basis swaps for the spread between the WTI Midland price and the WTI Cushing price.

Under the Company's costless collar contracts, a three-way collar is a combination of three options: a ceiling call, a floor put, and a short put. The counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the ceiling price to a maximum of the difference between the floor price and the short put price. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the ceiling price. If the settlement price is between the floor and the ceiling price, there is no payment required.

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 Crude Oil Brent, 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 March 31, 2018, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	2018		2019	
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
Oil Swaps - WTI	7,515,000	$ 51.26	1,638,000	$ 52.78
Oil Swaps - BRENT	1,650,000	$ 54.99	0	$ —
Oil Basis Swaps	4,125,000	$ (0.88)	0	$ —
Natural Gas Swaps	5,500,000	$ 3.03	0	$ —

Balance sheet offsetting of derivative assets and liabilities

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

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of March 31, 2018 and December 31, 2017.

	March 31, 2018	December 31, 2017
	(in thousands)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$ —	$ 531
Net amounts of assets presented in the Consolidated Balance Sheet	—	531
Gross amounts of liabilities presented in the Consolidated Balance Sheet	106,177	106,670
Net amounts of liabilities presented in the Consolidated Balance Sheet	$ 106,177	$ 106,670

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

	March 31, 2018	December 31, 2017
	(in thousands)	
Current assets: derivative instruments	$ —	$ 531
Noncurrent assets: derivative instruments	—	—
Total assets	$ —	$ 531
Current liabilities: derivative instruments	$ 99,685	$ 100,367
Noncurrent liabilities: derivative instruments	6,492	6,303
Total liabilities	$ 106,177	$ 106,670

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

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Change in fair value of open non-hedge derivative instruments	$ (38)	$ 39,375
Loss on settlement of non-hedge derivative instruments	(32,307)	(1,674)
Gain (loss) on derivative instruments	$ (32,345)	$ 37,701

15. 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 swaps, fixed price basis swaps and costless collars are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2018 and December 31, 2017.

	March 31, 2018	December 31, 2017
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$ —	$ —
Significant other observable inputs level 2	(106,177)	(106,139)
Significant unobservable inputs level 3	—	—
Total	$ (106,177)	$ (106,139)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

	March 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 166,000	$ 166,000	$ 397,000	$ 397,000
4.750% Senior Notes due 2024	500,000	496,250	500,000	501,855
5.375% Senior Notes due 2025	800,000	813,200	500,000	515,000
Partnership revolving credit facility	240,500	240,500	93,500	93,500

The fair value of the revolving credit facility and the Partnership's revolving credit facility approximates their carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the March 31, 2018 quoted market price, a Level 1 classification in the fair value hierarchy.

16. 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.

17. SUBSEQUENT EVENTS

Commodity Contracts

Subsequent to March 31, 2018, the Company entered into new fixed price swaps and three-way costless collars. 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 Crude Oil Brent.

The following tables present the derivative contracts entered into by the Company subsequent to March 31, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
January 2019 - December 2019		
Oil Swaps - WTI	273,000	$ 57.96

	January 2019 - June 2019	
Oil Three-Way Collars	***WTI***	**Brent**
Volume (Bbls)	1,810,000	724,000
Short put price (per Bbl)	$ 45.00	$ 55.00
Floor price (per Bbl)	$ 55.00	$ 65.00
Ceiling price (per Bbl)	$ 70.31	$ 77.85

Proposed Tax Status Election and Related Transactions of the Partnership

On March 29, 2018, the Partnership announced that the Board of Directors of its General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election (the "Tax Status Election"). In connection with making this election, on May 9, 2018, the Partnership (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC (the "Operating Company"), (iii) amended and restated its existing registration rights agreement with Diamondback and (iv) entered into an exchange agreement with Diamondback, the General Partner and the Operating Company. Simultaneously with the effectiveness of these agreements, Diamondback delivered and assigned to the Partnership the 73,150,000 common units it owned in exchange for (i) 73,150,000 newly-issued Class B Units of the Partnership and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018. The Tax Status Election was effective on May 10, 2018. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) the Company made a cash capital contribution of $1.0 million to the Partnership in respect of its Class B Units. The Company, as the holder of the Class B Units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on their invested capital. None of the transactions undertaken as part of the change in the Partnership's tax status are expected to be taxable to the Company. On May 10, 2018, the Company also exchanged 731,500 Class B Units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital made in respect of the Class B Units.

The Company's Credit Facility

In connection with the Company's spring 2018 redetermination, the agent lender under the credit agreement has recommended that the Company's borrowing base be increased to $2.0 billion. This increase is subject to approval of the required other lenders. Notwithstanding such adjustment, the Company intends to continue to limit the lenders' aggregate commitment to $1.0 billion.

The Partnership's Credit Facility

In connection with the Partnership's spring 2018 redetermination, the agent lender under the credit agreement has recommended that the Partnership's borrowing base be increased to $475.0 million. This increase is subject to approval of the required other lenders.

18. GUARANTOR FINANCIAL STATEMENTS

As of March 31, 2018, Diamondback E&P LLC and Diamondback O&G LLC (the "Guarantor Subsidiaries") are guarantors under the indentures relating to the 2024 Senior Notes and the 2025 Senior Notes, as supplemented. In connection with the issuance of the 2024 Senior Notes and the 2025 Senior Notes (including the New 2025 Senior Notes), the Partnership, the General Partner, Viper Energy Partners LLC and Rattler Midstream LLC were designated as Non-Guarantor Subsidiaries. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 18 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
March 31, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non– Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 28,247	$ 26,089	$ 18,151	$ —	$ 72,487
Accounts receivable	—	207,407	28,873	—	236,280
Accounts receivable - related party	—	—	6,505	(6,505)	—
Intercompany receivable	2,869,030	654,684	—	(3,523,714)	—
Inventories	—	8,963	—	—	8,963
Other current assets	538	5,838	361	—	6,737
Total current assets	2,897,815	902,981	53,890	(3,530,219)	324,467
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	8,390,912	1,258,327	(414)	9,648,825
Midstream assets	—	295,161	—	—	295,161
Other property, equipment and land	—	82,095	—	—	82,095
Accumulated depletion, depreciation, amortization and impairment	—	(2,074,783)	(200,992)	866	(2,274,909)
Net property and equipment	—	6,693,385	1,057,335	452	7,751,172
Funds held in escrow	—	10	—	—	10
Investment in subsidiaries	3,992,760	—	—	(3,992,760)	—
Investment in real estate	—	109,103	—	—	109,103
Other assets	—	21,312	18,824	—	40,136
Total assets	$ 6,890,575	$ 7,726,791	$ 1,130,049	$ (7,522,527)	$ 8,224,888
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 62,553	$ 576	$ —	$ 63,129
Intercompany payable	—	3,530,219	—	(3,530,219)	—
Other current liabilities	25,711	516,910	1,918	—	544,539
Total current liabilities	25,711	4,109,682	2,494	(3,530,219)	607,668
Long-term debt	1,295,412	166,000	240,500	—	1,701,912
Derivative instruments	—	6,492	—	—	6,492
Asset retirement obligations	—	21,258	—	—	21,258
Deferred income taxes	152,369	—	—	—	152,369
Other long term liabilities	—	7	—	—	7
Total liabilities	1,473,492	4,303,439	242,994	(3,530,219)	2,489,706
Commitments and contingencies					
Stockholders' equity	5,417,083	3,423,352	887,055	(4,310,407)	5,417,083
Non-controlling interest	—	—	—	318,099	318,099
Total equity	5,417,083	3,423,352	887,055	(3,992,308)	5,735,182
Total liabilities and equity	$ 6,890,575	$ 7,726,791	$ 1,130,049	$ (7,522,527)	$ 8,224,888

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

Condensed Consolidated Balance Sheet
December 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 54,074	$ 34,175	$ 24,197	$ —	$ 112,446
Accounts receivable	—	205,859	25,754	—	231,613
Accounts receivable - related party	—	—	5,142	(5,142)	—
Intercompany receivable	2,624,810	2,267,308	—	(4,892,118)	—
Inventories	—	9,108	—	—	9,108
Other current assets	618	4,461	355	—	5,434
Total current assets	2,679,502	2,520,911	55,448	(4,897,260)	358,601
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	8,129,211	1,103,897	(414)	9,232,694
Midstream assets	—	191,519	—	—	191,519
Other property, equipment and land	—	80,776	—	—	80,776
Accumulated depletion, depreciation, amortization and impairment	—	(1,976,248)	(189,466)	4,342	(2,161,372)
Net property and equipment	—	6,425,258	914,431	3,928	7,343,617
Funds held in escrow	—	—	6,304	—	6,304
Investment in subsidiaries	3,809,557	—	—	(3,809,557)	—
Other assets	—	25,609	36,854	—	62,463
Total assets	$ 6,489,059	$ 8,971,778	$ 1,013,037	$ (8,702,889)	$ 7,770,985
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ 1	$ 91,629	$ 2,960	$ —	$ 94,590
Intercompany payable	132,067	4,765,193	—	(4,897,260)	—
Other current liabilities	7,236	472,933	2,669	—	482,838
Total current liabilities	139,304	5,329,755	5,629	(4,897,260)	577,428
Long-term debt	986,847	397,000	93,500	—	1,477,347
Derivative instruments	—	6,303	—	—	6,303
Asset retirement obligations	—	20,122	—	—	20,122
Deferred income taxes	108,048	—	—	—	108,048
Total liabilities	1,234,199	5,753,180	99,129	(4,897,260)	2,189,248
Commitments and contingencies					
Stockholders' equity	5,254,860	3,218,598	913,908	(4,132,506)	5,254,860
Non-controlling interest	—	—	—	326,877	326,877
Total equity	5,254,860	3,218,598	913,908	(3,805,629)	5,581,737
Total liabilities and equity	$ 6,489,059	$ 8,971,778	$ 1,013,037	$ (8,702,889)	$ 7,770,985

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 363,581	$ —	$ 55,687	$ 419,268
Natural gas sales	—	11,800	—	2,578	14,378
Natural gas liquid sales	—	28,985	—	4,128	33,113
Royalty income	—	—	62,393	(62,393)	—
Midstream services	—	11,395	—	—	11,395
Other operating income	—	1,991	50	—	2,041
Total revenues	—	417,752	62,443	—	480,195
Costs and expenses:					
Lease operating expenses	—	37,345	—	—	37,345
Production and ad valorem taxes	—	23,065	4,239	—	27,304
Gathering and transportation	—	4,020	265	—	4,285
Midstream services	—	11,189	—	—	11,189
Depreciation, depletion and amortization	—	100,216	11,525	3,475	115,216
General and administrative expenses	7,490	6,739	2,711	(615)	16,325
Asset retirement obligation accretion	—	355	—	—	355
Other operating expense	—	530	—	—	530
Total costs and expenses	7,490	183,459	18,740	2,860	212,549
Income (loss) from operations	(7,490)	234,293	43,703	(2,860)	267,646
Other income (expense)					
Interest expense, net	(8,932)	(2,671)	(2,098)	—	(13,701)
Other income, net	123	2,836	392	(615)	2,736
Loss on derivative instruments, net	—	(32,345)	—	—	(32,345)
Gain on revaluation of investment	—	—	899	—	899
Total other expense, net	(8,809)	(32,180)	(807)	(615)	(42,411)
Income (loss) before income taxes	(16,299)	202,113	42,896	(3,475)	225,235
Provision for income taxes	47,081	—	—	—	47,081
Net income (loss)	(63,380)	202,113	42,896	(3,475)	178,154
Net income attributable to non-controlling interest	—	—	—	15,342	15,342
Net income (loss) attributable to Diamondback Energy, Inc.	$ (63,380)	$ 202,113	$ 42,896	$ (18,817)	$ 162,812

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 178,230	$ —	$ 28,844	$ 207,074
Natural gas sales	—	8,575	—	1,347	9,922
Natural gas liquid sales	—	13,643	—	1,859	15,502
Royalty income	—	—	32,050	(32,050)	—
Lease bonus income	—	—	1,602	—	1,602
Midstream services	—	1,130	—	—	1,130
Total revenues	—	201,578	33,652	—	235,230
Costs and expenses:					
Lease operating expenses	—	26,626	—	—	26,626
Production and ad valorem taxes	—	13,655	2,070	—	15,725
Gathering and transportation	—	2,476	143	—	2,619
Midstream services	—	854	—	—	854
Depreciation, depletion and amortization	—	50,891	7,847	191	58,929
General and administrative expenses	7,108	5,109	2,142	(615)	13,744
Asset retirement obligation accretion	—	323	—	—	323
Total costs and expenses	7,108	99,934	12,202	(424)	118,820
Income (loss) from operations	(7,108)	101,644	21,450	424	116,410
Other income (expense)					
Interest expense, net	(10,808)	(805)	(612)	—	(12,225)
Other income (expense), net	1,092	854	(186)	(615)	1,145
Gain on derivative instruments, net	—	37,701	—	—	37,701
Total other expense, net	(9,716)	37,750	(798)	(615)	26,621
Income (loss) before income taxes	(16,824)	139,394	20,652	(191)	143,031
Provision for income taxes	1,957	—	—	—	1,957
Net income (loss)	(18,781)	139,394	20,652	(191)	141,074
Net income attributable to non-controlling interest	—	—	—	4,801	4,801
Net income (loss) attributable to Diamondback Energy, Inc.	$ (18,781)	$ 139,394	$ 20,652	$ (4,992)	$ 136,273

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 26,895	$ 263,320	$ 49,212	$ —	$ 339,427
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(280,015)	—	—	(280,015)
Additions to midstream assets	—	(38,395)	—	—	(38,395)
Purchase of other property, equipment and land	—	(1,947)	—	—	(1,947)
Acquisition of leasehold interests	—	(16,011)	—	—	(16,011)
Acquisition of mineral interests	—	(19)	(149,994)	—	(150,013)
Proceeds from sale of assets	—	—	125	—	125
Funds held in escrow	—	10,989	—	—	10,989
Intercompany transfers	(86,679)	86,679	—	—	—
Investment in real estate	—	(109,664)	—	—	(109,664)
Net cash used in investing activities	(86,679)	(348,383)	(149,869)	—	(584,931)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	77,000	147,000	—	224,000
Repayment under credit facility	—	(308,000)	—	—	(308,000)
Proceeds from senior notes	312,000	—	—	—	312,000
Debt issuance costs	(3,692)	(23)	(3)	—	(3,718)
Distributions from subsidiary	33,649	—	—	(33,649)	—
Distributions to non-controlling interest	—	—	(52,386)	33,649	(18,737)
Intercompany transfers	(308,000)	308,000	—	—	—
Net cash provided by financing activities	33,957	76,977	94,611	—	205,545
Net decrease in cash and cash equivalents	(25,827)	(8,086)	(6,046)	—	(39,959)
Cash and cash equivalents at beginning of period	54,074	34,175	24,197	—	112,446
Cash and cash equivalents at end of period	$ 28,247	$ 26,089	$ 18,151	$ —	$ 72,487

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 40	$ 149,822	$ 26,065	$ —	$ 175,927
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(116,174)	—	—	(116,174)
Purchase of other property, equipment and land	—	(11,918)	—	—	(11,918)
Acquisition of leasehold interests	—	(1,760,810)	—	—	(1,760,810)
Acquisition of mineral interests	—	—	(8,579)	—	(8,579)
Acquisition of midstream assets	—	(48,329)	—	—	(48,329)
Additions to midstream assets	—	(59)	—	—	(59)
Proceeds from sale of assets	—	1,238	—	—	1,238
Funds held in escrow	—	119,340	—	—	119,340
Equity investments	—	(188)	—	—	(188)
Intercompany transfers	(1,660,917)	1,660,917	—	—	—
Net cash used in investing activities	(1,660,917)	(155,983)	(8,579)	—	(1,825,479)
Cash flows from financing activities:					
Repayment under credit facility	—	—	(120,500)	—	(120,500)
Debt issuance costs	(409)	(8)	(1)	—	(418)
Public offering costs	(79)	—	(186)	—	(265)
Proceeds from public offerings	—	—	147,725	—	147,725
Distributions from subsidiary	18,692	—	—	(18,692)	—
Exercise of stock options	358	—	—	—	358
Distributions to non-controlling interest	—	—	(25,174)	18,692	(6,482)
Net cash provided by (used in) financing activities	18,562	(8)	1,864	—	20,418
Net increase (decrease) in cash and cash equivalents	(1,642,315)	(6,169)	19,350	—	(1,629,134)
Cash and cash equivalents at beginning of period	1,643,226	14,135	9,213	—	1,666,574
Cash and cash equivalents at end of period	$ 911	$ 7,966	$ 28,563	$ —	$ 37,440

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, 2017. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Part II. Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are 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 horizontal development of the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Spring formations in the Delaware Basin. We intend to continue to develop our reserves and increase production through development drilling and 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 March 31,	
	2018	2017
Oil (MBbls)	74%	75%
Natural gas (MMcf)	12%	11%
Natural gas liquids (MBbls)	14%	14%
	100%	100%

As of March 31, 2018, we had approximately 207,336 net acres, which consisted of approximately 102,511 net acres in the Northern Midland Basin and approximately 104,825 net acres in the Southern Delaware Basin. We have an estimated 3,800 gross horizontal locations that we believe to be economic at $60 per Bbl West Texas Intermediate, or WTI.

In the first quarter of 2018, 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 operating expenses while improving cash operating margins on a per BOE and percentage basis. In doing so, we achieved another quarter of robust production growth within cash flow, which has allowed us to maintain what we believe to be a peer leading leverage ratio. We are currently operating 11 drilling rigs and five completion crews and plan to operate between 10 and 12 drilling rigs for the remainder of 2018 at current commodity prices.

2018 Highlights

Operational Update

During the three months ended March 31, 2018, we drilled 41 gross (36 net) operated horizontal wells, of which 14 gross (13 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 35 gross (30 net) operated horizontal wells into production, of which six gross (six net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin.

We are currently operating 11 drilling rigs and intend to operate between 10 and 12 drilling rigs during 2018 across our asset base in the Midland and Delaware Basins, based on current commodity prices. We plan to operate six to seven of these drilling rigs in the Midland Basin targeting horizontal development of the Wolfcamp and Spraberry formations, while the remainder of the drilling rigs are expected to operate in the Delaware Basin targeting the Wolfcamp and Bone Spring formations.

In the Midland Basin, we continue to see positive well results from our core development areas in Midland, Glasscock, Howard, Andrews and Martin counties. Assuming commodity prices at current levels, we anticipate operating between six and seven drilling rigs across our Northern Midland Basin acreage for the remainder of 2018.

In the Delaware Basin, we are currently operating five drilling rigs, with plans to operate between five and six drilling rigs for the remainder of 2018. Our 2018 development plan is primarily focused on long-lateral Wolfcamp A wells in Pecos, Reeves and Ward counties. Additionally, in 2018 we expect to conduct further appraisal of the Second Bone Spring interval in Pecos county as well as the Wolfcamp B interval in Reeves and Ward counties.

We continue to focus on low cost operations and best in class execution. In doing so, we are focused on controlling oilfield service costs as our service providers seek additional pricing increases after a prolonged period of declining costs in 2015 and 2016. To combat rising service costs, we have taken proactive measures such as securing frac sand supply for future well completions and will continue to seek opportunities to control and de-bundle additional costs where possible. We believe that our 2018 drilling and completion budget covers potential increases in our service costs during the year.

Proposed Tax Status Election and Related Transactions by Viper

On March 29, 2018, Viper announced that the Board of Directors of its general partner had unanimously approved a change of Viper’s federal income tax status from that of a pass-through partnership to that of a taxable entity via a “check the box” election. In connection with making this election, on May 9, 2018 Viper (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, or the Operating Company, (iii) amended and restated its existing registration rights agreement with us and (iv) entered into an exchange agreement with us, Viper’s general partner, or the General Partner, and the Operating Company. Simultaneously with the effectiveness of these agreements, we delivered and assigned to Viper the 73,150,000 common units we owned in exchange for (i) 73,150,000 of Viper’s newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018, or the Recapitalization Agreement. Immediately following that exchange, Viper continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and we owned the remaining approximately 64% of the outstanding units issued by the Operating Company. The Operating Company units and Viper’s Class B units owned by us are exchangeable from time to time for Viper’s common units (that is, one Operating Company unit and one Viper Class B unit, together, will be exchangeable for one Viper common unit).

On May 10, 2018, the change in Viper’s income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to Viper in respect of its general partner interest and (ii) we made a cash capital contribution of $1.0 million to Viper in respect of the Class B Units. We, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, we also exchanged 731,500 Class B Units and 731,500 units in the Operating Company for 731,500 common units of Viper and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B Units. The General Partner, our wholly-owned subsidiary, continues to serve as Viper’s general partner. Accordingly, we continue to control Viper and its financial results will continue to be consolidated with ours. None of the transactions undertaken as part of the change in Viper’s tax status are expected to be taxable to us. After the effectiveness of the tax status election and the completion of related transactions, Viper’s minerals business will continue to be conducted through the Operating Company, which will be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to Viper’s business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to Viper’s Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018.

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

	Three Months Ended March 31,	
	2018	2017
Oil (Bbls)/d	75,557	46,201
Natural Gas (Mcf)/d	72,728	40,923
Natural Gas Liquids (Bbls)/d	14,929	8,589
Total average production per day (BOE)	102,607	61,610

Our average daily production for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 increased 40,997 BOE/d, or 66.5%.

Sources of Our Revenues

Our main sources of revenues are 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 March 31,	
	2018	2017
Revenues		
Oil sales	90%	89%
Natural gas sales	3%	4%
Natural gas liquid sales	7%	7%
	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 or natural gas liquids prices. Oil, natural gas and natural gas liquids prices have historically been volatile. During 2017, WTI posted prices ranged from $42.48 to $60.46 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. During the first three months of 2018, WTI posted prices ranged from $59.20 to $66.27 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On March 29, 2018, the WTI posted price for crude oil was $64.87 per Bbl and the Henry Hub spot market price of natural gas was $2.81 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.

Results of Operations

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(in thousands, except Bbl, Mcf and BOE amounts)	
Revenues		
Oil, natural gas and natural gas liquids	$ 466,759	$ 232,498
Lease bonus	—	1,602
Midstream services	11,395	1,130
Other operating income	2,041	—
Total revenues	480,195	235,230
Operating expenses		
Lease operating expenses	37,345	26,626
Production and ad valorem taxes	27,304	15,725
Gathering and transportation	4,285	2,619
Midstream services	11,189	854
Depreciation, depletion and amortization	115,216	58,929
General and administrative expenses	16,325	13,744
Asset retirement obligation accretion	355	323
Other operating expense	530	—
Total expenses	212,549	118,820
Income from operations	267,646	116,410
Interest expense, net	(13,701)	(12,225)
Other income, net	2,736	1,145
Gain (loss) on derivative instruments, net	(32,345)	37,701
Gain on revaluation of investment	899	—
Total other income (expense), net	(42,411)	26,621
Income before income taxes	225,235	143,031
Provision for income taxes	47,081	1,957
Net income	178,154	141,074
Net income attributable to non-controlling interest	15,342	4,801
Net income attributable to Diamondback Energy, Inc.	$ 162,812	$ 136,273

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Production Data:		
Oil (MBbls)	6,800	4,158
Natural gas (MMcf)	6,546	3,683
Natural gas liquids (MBbls)	1,344	773
Combined volumes (MBOE)	9,235	5,545
Daily combined volumes (BOE/d)	102,607	61,610
Average Prices:		
Oil (per Bbl)	$ 61.66	$ 49.80
Natural gas (per Mcf)	2.20	2.69
Natural gas liquids (per Bbl)	24.64	20.05
Combined (per BOE)	50.55	41.93
Oil, hedged ($ per Bbl)(1)	56.82	49.40
Natural gas, hedged ($ per MMbtu)(1)	2.29	2.69
Average price, hedged ($ per BOE)(1)	47.05	41.63
Average Costs per BOE:		
Lease operating expense	$ 4.04	$ 4.80
Production and ad valorem taxes	2.96	2.84
Gathering and transportation expense	0.46	0.47
General and administrative - cash component	0.96	1.20
Total operating expense - cash	8.42	9.31
General and administrative - non-cash component	0.81	1.28
Depreciation, depletion and amortization	12.48	10.63
Interest expense, net	1.48	2.20
Total expenses	14.77	14.11
Average realized oil price ($/Bbl)	$ 61.66	$ 49.80
Average NYMEX ($/Bbl)	62.91	51.62
Differential to NYMEX	(1.25)	(1.82)
Average realized oil price to NYMEX	98%	96%
Average realized natural gas price ($/Mcf)	$ 2.20	$ 2.69
Average NYMEX ($/Mcf)	3.08	3.02
Differential to NYMEX	(0.88)	(0.33)
Average realized natural gas price to NYMEX	71%	89%
Average realized natural gas liquids price ($/Bbl)	$ 24.64	$ 20.05
Average NYMEX oil price ($/Bbl)	62.91	51.62
Average realized natural gas liquids price to NYMEX oil price	39%	39%

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

Comparison of the Three Months Ended March 31, 2018 and 2017

Oil, Natural Gas and Natural Gas Liquids Revenues. Our oil, natural gas and natural gas liquids revenues increased by approximately $234.3 million, or 101%, to $466.8 million for the three months ended March 31, 2018 from $232.5 million for the three months ended March 31, 2017. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 40,997 BOE/d to 102,607 BOE/d during the three months ended March 31, 2018 from 61,610 BOE/d during the three months ended March 31, 2017. The total increase in revenue of approximately $234.3 million is largely attributable to higher oil, natural gas and natural gas liquids production volumes and higher average sales prices for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,642,003 Bbls of oil, 570,623 Bbls of natural gas liquids and 2,862,436 Mcf of natural gas for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017.

The net dollar effect of the increases in prices of approximately $83.6 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas and natural gas liquids) and the net dollar effect of the increase in production of approximately $150.7 million (calculated as the increase in period-to-period volumes for oil, natural gas and natural gas liquids 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	$ 11.86	6,800	$ 80,611
Natural gas	(0.49)	6,546	(3,207)
Natural gas liquids	4.59	1,344	6,167
Total revenues due to change in price			$ 83,571

	Change in production volumes(1)	Prior period Average Prices	Total net dollar effect of change
			(in thousands)
Effect of changes in production volumes:			
Oil	2,642	$ 49.80	$ 131,535
Natural gas	2,862	2.69	7,711
Natural gas liquids	571	20.05	11,444
Total revenues due to change in production volumes			150,690
Total change in revenues			$ 234,261

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

Lease Bonus Revenue. During the three months ended March 31, 2018, we did not receive any lease bonus revenue. Lease bonus revenue was $1.6 million for the three months ended March 31, 2017 attributable to lease bonus payments to extend the term of one lease, reflecting an average bonus of $2,500 per acre.

Midstream Services Revenue. Midstream services revenue was $11.4 million for the three months ended March 31, 2018, an increase of $10.3 million as compared to $1.1 million for the three months ended March 31, 2017. We began generating midstream services revenue during the first quarter of 2017 and, prior to that period, had no midstream services revenue. Our midstream services revenue represents fees charged to our joint interest owners and third parties for the transportation of oil and natural gas along with water gathering and related disposal facilities. These assets complement our operations in areas where we have significant production.

Lease Operating Expense. Lease operating expense was $37.3 million ($4.04 per BOE) for the three months ended March 31, 2018 as compared to $26.6 million ($4.80 per BOE) for the three months ended March 31, 2017. The decrease in lease operating expense per BOE was a result of higher production volumes.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $27.3 million for the three months ended March 31, 2018, an increase of $11.6 million, or 74%, from $15.7 million for the three months ended March 31, 2017. 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 March 31, 2018, our production and ad valorem taxes per BOE increased by $0.12 as compared to the three months ended March 31, 2017, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $11.2 million for the three months ended March 31, 2018, an increase of $10.3 million as compared to $0.9 million for the three months ended March 31, 2017. Prior to the first quarter of 2017, we had no midstream services expense. Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $56.3 million, or 96%, to $115.2 million for the three months ended March 31, 2018 from $58.9 million for the three months ended March 31, 2017.

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

	Three Months Ended March 31,	
	2018	**2017**
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$ 108,987	$ 58,138
Depreciation of midstream assets	4,502	435
Depreciation of other property and equipment	1,727	356
Depreciation, depletion and amortization expense	$ 115,216	$ 58,929
Oil and natural gas properties depreciation, depletion and amortization per BOE	$ 11.80	$ 10.49

The increase in depletion of proved oil and natural gas properties of $50.8 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 resulted primarily from higher production levels and an increase in net book value on new reserves added.

General and Administrative Expenses. General and administrative expenses increased $2.6 million from $13.7 million for the three months ended March 31, 2017 to $16.3 million for the three months ended March 31, 2018. The increase was primarily due to an increase in salaries and benefits.

Net Interest Expense. Net interest expense for the three months ended March 31, 2018 was $13.7 million as compared to $12.2 million for the three months ended March 31, 2017, an increase of $1.5 million. This increase was due to a higher interest rate and increased borrowings during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017.

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 March 31, 2018 and 2017, we had a cash loss on settlement of derivative instruments of $32.3 million and $1.7 million, respectively. For the three months ended March 31, 2018, we had a negative change in the fair value of open derivative instruments of $38,000 as compared to a positive change of $39.4 million for the three months ended March 31, 2017.

Provision for Income Taxes. We recorded an income tax provision of $47.1 million and $2.0 million for the three months ended March 31, 2018 and 2017, respectively. The change in our income tax provision was primarily due to the increase in pre-tax book income for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017, and the change in the valuation allowance for the three months ended March 31, 2017.

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

Liquidity and Cash Flow

Our cash flows for the three months ended March 31, 2018 and 2017 are presented below:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Net cash provided by operating activities	$ 339,427	$ 175,927
Net cash used in investing activities	(584,931)	(1,825,479)
Net cash provided by financing activities	205,545	20,418
Net decrease in cash	$ (39,959)	$ (1,629,134)

Operating Activities

Net cash provided by operating activities was $339.4 million for the three months ended March 31, 2018 as compared to $175.9 million for the three months ended March 31, 2017. The increase in operating cash flows is primarily the result of an increase in our oil and natural gas revenues due to an increase in average prices and production growth during the three months ended March 31, 2018.

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 $584.9 million and $1,825.5 million during the three months ended March 31, 2018 and 2017, respectively.

During the three months ended March 31, 2018, we spent (a) $280.0 million on capital expenditures in conjunction with our development program, in which we drilled 41 gross (36 net) operated horizontal wells, of which 14 gross (13 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 35 gross (30 net) operated horizontal wells into production, of which six gross (six net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, (b) $38.4 million on additions to midstream assets, (c) $16.0 million on leasehold acquisitions, (d) $150.0 million for the acquisition of mineral interests and (e) $1.9 million for the purchase of other property and equipment.

During the three months ended March 31, 2017, we spent (a) $116.2 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 28 gross (23 net) horizontal wells, completed 26 gross (20 net) horizontal wells and participated in the drilling of six gross (one net) non-operated wells in the Permian Basin, (b) $1,760.8 million on leasehold acquisitions, (c) $48.3 million for the acquisition of midstream assets, (d) $8.6 million on mineral interest acquisitions and (e) $11.9 million for the purchase of other property and equipment.

Our investing activities for the three months ended March 31, 2018 and 2017 are summarized in the following table:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Drilling, completion and infrastructure	$ (280,015)	$ (116,174)
Additions to midstream assets	(38,395)	(59)
Acquisition of leasehold interests	(16,011)	(1,760,810)
Acquisition of mineral interests	(150,013)	(8,579)
Acquisition of midstream assets	—	(48,329)
Purchase of other property, equipment and land	(1,947)	(11,918)
Investment in real estate	(109,664)	—
Proceeds from sale of assets	125	1,238
Funds held in escrow	10,989	119,340
Equity investments	—	(188)
Net cash used in investing activities	$ (584,931)	$ (1,825,479)

Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2018 and 2017 was $205.5 million and $20.4 million, respectively. During the three months ended March 31, 2018, the amount provided by financing activities was primarily attributable to the issuance of $300.0 million of new senior notes and $12.0 million of premium on proceeds of the new senior notes, partially offset by $84.0 million of repayments, net of borrowings, and $18.7 million of distributions to non-controlling interest. The 2017 amount provided by financing activities was primarily attributable to $147.7 million of proceeds from Viper's January 2017 equity offering, partially offset by $120.5 million of repayments, net of borrowings, under Viper's credit facility.

2024 Senior Notes

On October 28, 2016, we issued $500.0 million in aggregate principal amount of 4.750% senior notes due 2024, which we refer to as the 2024 senior notes. The 2024 senior notes bear interest at a rate of 4.750% 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. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2024 senior notes; provided, however, that the 2024 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the our future unrestricted subsidiaries.

The 2024 senior notes were issued under, and are governed by, an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented. The 2024 indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our 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 capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

We may on any one or more occasions redeem some or all of the 2024 senior notes at any time on or after November 1, 2019 at the redemption prices (expressed as percentages of principal amount) of 103.563% for the 12-month period beginning on November 1, 2019, 102.375% for the 12-month period beginning on November 1, 2020, 101.188% for the 12-month period beginning on November 1, 2021 and 100.000% beginning on November 1, 2022 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to November 1, 2019, we may on any one or more occasions redeem all or a portion of the 2024 senior notes at a price equal to 100% of the principal amount of the 2024 senior notes plus a "make-whole" premium and accrued and unpaid interest to the redemption date. In addition, any time prior to November 1, 2019, we may on any one or more occasions redeem the 2024 senior notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2024 senior notes issued prior to such date at a redemption price of 104.750%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

2025 Senior Notes

On December 20, 2016, we issued $500.0 million in aggregate principal amount of 5.375% senior notes due 2025, which we refer to as the exiting 2025 notes, under an indenture (which, as may be amended or supplemented from time to time, is referred to as the 2025 Indenture) among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On July 27, 2017, we exchanged all of the existing 2025 notes for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act.

On January 29, 2018, we issued $300.0 million aggregate principal amount of new 5.375% senior notes due 2025, which we refer to as the new 2025 notes, as additional notes under the 2025 Indenture. The new 2025 notes were issued in a transaction exempt from the registration requirements under the Securities Act. We refer to the new 2025 notes, together with the existing 2025 notes, as the 2025 senior notes. We received approximately $308.4 million in net proceeds, after deducting the initial purchaser's discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2025 notes. We used the net proceeds from the issuance of the new 2025 notes to repay a portion of the outstanding borrowings under our revolving credit facility.

The 2025 senior notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year and will mature on May 31, 2025. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2025 senior notes; provided, however, that the 2025 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.

The 2025 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our 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 capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

We may on any one or more occasions redeem some or all of the 2025 senior notes at any time on or after May 31, 2020 at the redemption prices (expressed as percentages of principal amount) of 104.031% for the 12-month period beginning on May 31, 2020, 102.688% for the 12-month period beginning on May 31, 2021, 101.344% for the 12-month period beginning on May 31, 2022 and 100.000% beginning on May 31, 2023 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to May 31, 2020, we may on any one or more occasions redeem all or a portion of the 2025 senior notes at a price equal to 100% of the principal amount of the 2025 senior notes plus a "make-whole" premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 31, 2020, we may on any one or more occasions redeem the 2025 senior notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2025 senior notes issued prior to such date at a redemption price of 105.375%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

Under a registration rights agreement executed in connection with the issuance of the new 2025 notes, we and our subsidiary guarantors agreed to file, subject to certain conditions, a registration statement relating to the new 2025 notes with the SEC pursuant to which we will either offer to exchange the new 2025 notes for registered notes with substantially identical terms or, in certain circumstances, register the resale of the new 2025 notes. Additional interest on the new 2025 notes may become payable if we do not comply with our obligations under the registration rights agreement relating to the new 2025 notes.

Second Amended and Restated Credit Facility

Our credit agreement dated November 1, 2013, as amended and restated, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger, provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on our oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, we may request up to two additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2018, the borrowing base was set at $1.8 billion, we had elected a commitment amount of $1.0 billion and we had borrowings of $166.0 million outstanding under the revolving credit facility and $834.0 million available for future borrowings under our revolving credit facility. In connection with our spring 2018 redetermination, the agent lender under the credit agreement has recommended that our borrowing base be increased to $2.0 billion. This increase is subject to approval of the required other lenders. Notwithstanding such adjustment, we intend to continue to limit the lenders' aggregate commitment to $1.0 billion.

Diamondback O&G LLC is the borrower under our credit agreement. As of March 31, 2018, the credit agreement is guaranteed by us, Diamondback E&P LLC and Rattler Midstream LLC (formerly known as White Fang Energy LLC) and will also be guaranteed by any of our future subsidiaries that are classified as restricted subsidiaries under the credit agreement. The credit agreement is also secured by substantially all of our assets and the assets of Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a per annum 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 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, each of which applicable margin rates is increased by 0.25% per annum if the total debt to EBITDAX ratio is greater than 3.0 to 1.0. The applicable margin depends on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. 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 loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022.

The 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, as amended in November 2017, allows for the issuance of unsecured debt in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.

As of March 31, 2018, 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, as administrative agent, and Wells Fargo Securities, as sole book runner and lead arranger. The credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on Viper's oil and natural gas reserves and other factors (the "borrowing base") of $400.0 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, Viper may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2018, the borrowing base was set at $400.0 million, and Viper had $240.5 million of outstanding borrowings and $159.5 million available for future borrowings under its revolving credit facility. In connection with Viper's spring 2018 redetermination, the agent lender under the credit agreement has recommended that Viper's borrowing base be increased to $475.0 million. This increase is subject to approval of the required other lenders.

The outstanding borrowings under Viper's credit agreement bear interest at a per annum rate elected by Viper that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. Viper is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of Viper and its subsidiary's assets.

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

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.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2018 capital budget for drilling and infrastructure of approximately $1.3 billion to $1.5 billion, representing an increase of 60% over our 2017 capital budget. We estimate that, of these expenditures, approximately:

- $1,175.0 million to $1,325.0 million will be spent on drilling and completing 170 to 190 gross (146 to 163 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins; and

- $125.0 million to $175.0 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

During the three months ended March 31, 2018, our aggregate capital expenditures for our development program were $280.0 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the three months ended March 31, 2018, we spent approximately $16.0 million in cash on acquisitions of leasehold interests and mineral acres.

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. We are currently operating 11 drilling rigs and five 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 prices and production expectations for 2018, 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 2018. 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 2018 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 a 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 16 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, 2017.

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, 2017.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of March 31, 2018. Please read Note 16 included in Notes to the 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 and costless collars, to reduce price volatility associated with certain of our oil and natural gas 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 and Crude Oil - Brent and with natural gas derivative settlements based on NYMEX Henry Hub pricing.

At March 31, 2018 and December 31, 2017, we had a net liability derivative position of $106.2 million and $106.7 million, respectively, related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of March 31, 2018, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $172.8 million, an increase of $66.6 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net asset derivative position to $39.6 million, a decrease of $66.6 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 $71.0 million at March 31, 2018) and receivables from the sale of our oil and natural gas production (approximately $165.3 million at March 31, 2018).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the three months ended March 31, 2018, two purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (30%) and Koch Supply & Trading LP (20%). For the three months ended March 31, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (42%); Koch Supply & Trading LP (18%); 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 March 31, 2018, we had five customers that represented approximately 86% of our total joint operations receivables. At December 31, 2017, we had three customers that represented approximately 74% 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 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base.

As of March 31, 2018, we had $166.0 million in outstanding borrowings under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 3.05%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $1.7 million based on an aggregate of $166.0 million outstanding under our revolving credit facility as of March 31, 2018.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of March 31, 2018, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of March 31, 2018, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2018 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, 2017. 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, 2017.

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	Indenture, dated as of December 20, 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 5.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 21, 2016).
4.6	First Supplemental Indenture, dated as of January 29, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on January 30, 2018).
4.7	Registration Rights Agreement, dated as of January 29, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on January 30, 2018).
4.8	Registration Rights Agreement, dated as of February 28, 2017, by and among Diamondback Energy, Inc., Brigham Resources, LLC, Brigham Resources Operating, LLC and Brigham Resources Upstream Holdings, LP (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 6, 2017).
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.

* 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:	May 10, 2018	/s/ Travis D. Stice
		Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date:	May 10, 2018	/s/ Teresa L. Dick
		Teresa L. Dick Chief Financial Officer (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: May 10, 2018

/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: May 10, 2018

/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: May 10, 2018	/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:	May 10, 2018	/s/ Teresa L. Dick
		Teresa L. Dick
		Chief Financial Officer