Diamondback Energy, Inc.
Form 10-K
February 19, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

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

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§

232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

Large Accelerated Filer	ý	Accelerated Filer	¨
Non-Accelerated Filer	¨	Smaller Reporting Company	¨

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2015 was approximately $4,709,835,344.

As of February 16, 2016, 71,397,041 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2016 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K

DIAMONDBACK ENERGY, INC
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms used in this report:

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels per day.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
Brent	Brent sweet light crude oil.
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.
Condensate	Liquid hydrocarbons associated with the production that is primarily natural gas.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Developed acreage	Acreage assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole or dry well	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Estimated Ultimate Recovery or EUR	Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
Exploitation	A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Finding and development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Fracturing	The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons.

MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf	Thousand cubic feet of natural gas.
Mcf/d	Thousand cubic feet per day.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.
MMcf	Million cubic feet of natural gas.

Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD	Proved undeveloped.
Productive well	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion	The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
Reserves	Reserves are 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 should not be 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.
Resource play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
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 or operations.
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.
Stratigraphic play	An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.
Structural play	An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.
Tight formation	A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
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.
WTI	West Texas Intermediate.

GLOSSARY OF CERTAIN OTHER TERMS

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

2012 Plan	The Company's 2012 Equity Incentive Plan.
Bison	Bison Drilling and Field Services, LLC.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
EPA	U.S. Environmental Protection Agency.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Indenture	The indenture relating to the Senior Notes, dated as of September 18, 2013, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
Muskie	Muskie Proppant LLC.
NYMEX	New York Mercantile Exchange.
OSHA	Federal Occupational Safety and Health Act.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated as of June 23, 2014, entered into by the General Partner and Diamondback in connection with the closing of the Viper Offering.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Senior Notes	The Company's 7.625% senior unsecured notes due 2021 in the aggregate principal amount of $450 million.
Viper	Viper Energy Partners L.P.
Viper LTIP	Viper Energy Partners L.P. 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 of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “contir “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 Annual Report on Form 10–K, including under Part I, Item 1A. “Risk Factors” in this report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- 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.

PART I

Except as noted, in this Annual Report on Form 10-K, we refer to Diamondback, together with its consolidated subsidiaries, as "we," "us," "our," or "the Company". This report includes certain terms commonly used in the oil and gas industry, which are defined above in the "Glossary of Oil and Natural Gas Terms."

ITEM 1. BUSINESS AND PROPERTIES

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. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators.

We began operations in December 2007 with our acquisition of 4,174 net acres in the Permian Basin. At December 31, 2015, our total net acreage position in the Permian Basin was approximately 84,683 net acres. In addition, we, through our subsidiary Viper Energy Partners LP, or Viper, own mineral interests underlying approximately 46,562 gross (17,060 net) acres primarily in Midland County, Texas in the Permian Basin. Approximately 60% of these net acres are operated by us. On June 23, 2014, Viper completed its initial public offering of 5,750,000 common units representing limited partner interests and, on September 19, 2014 Viper completed a follow-on underwritten public offering of 3,500,000 common units. The common units sold to the public represent, in the aggregate, an approximate 12% limited partner interest in Viper. We own Viper Energy Partners GP LLC, the general partner of Viper, which we refer to as the general partner, and the remaining approximate 88% limited partner interest in Viper.

Our activities are primarily focused on the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations, which we refer to collectively as the Wolfberry play. The Wolfberry play is characterized by high oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates. The Wolfberry play is a modification and extension of the Spraberry play, the majority of which is designated in the Spraberry Trend Area field. According to the U.S. Energy Information Administration, the Spraberry Trend Area ranked as the second largest oilfield in the United States, based on 2009 reserves.

As of December 31, 2015, our estimated proved oil and natural gas reserves were 156,900 MBOE (which includes estimated reserves of 26,345 MBOE attributable to the mineral interests owned by Viper), based on reserve reports prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 59% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 107 gross (86 net) horizontal well locations and 3 gross (2 net) vertical well locations on 40-acre spacing in which we have a working interest and 16 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2015, our estimated proved reserves were approximately 67% oil, 17% natural gas liquids and 16% natural gas.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 1,500 gross (960 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $40.00 per Bbl WTI. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through additional acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves.

The challenging commodity price environment that we experienced in 2015 has continued in 2016, with the posted price of WTI dropping to as low as $26.68 in January 2016. Nevertheless, we believe we remain well-positioned in this environment. During 2015, we again demonstrated our operational focus on achieving best-in-class execution, low-cost operations and a conservative balance sheet as we continued to reduce drilling days, well costs and operating expenses while maintaining what we believe to be a peer leading leverage ratio. We intend to continue our operational focus in 2016, emphasizing financial discipline over growth. We currently intend to release one of our three horizontal drilling rigs in March 2016. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans in response to market conditions. We are prepared to decelerate our drilling program if commodity prices deteriorate and accelerate our drilling program if commodity prices improve. We have the option to release a second rig in the second quarter of 2016. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources.”

Our Business Strategy

Our business strategy is to continue to profitably grow our business through the following:

- Grow production and reserves by developing our oil-rich resource base. We intend to drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital.

- Focus on increasing hydrocarbon recovery through horizontal drilling and increased well density. We have targeted various intervals in the Wolfberry play through horizontal drilling and believe that there are opportunities to target additional intervals in the Wolfberry play with horizontal wells. Our initial horizontal focus had been on the Wolfcamp B interval, but our recent focus has primarily been on the Lower Spraberry interval. We have also begun to derisk the Wolfcamp A and Middle Spraberry on some of our properties. Our first two horizontal wells were completed in 2012 and had lateral lengths of less than 4,000 feet. As of December 31, 2015, we had drilled 188 horizontal wells as operator and had participated in 25 additional horizontal wells as a non-operator, including two in which we own only a minor wellbore interest. We also acquired interest in 11 horizontal wells on properties we purchased. Of these 224 total horizontal wells, 184 had been completed and were on production. Of the 184 horizontal wells on production, 112 are in the Wolfcamp B interval, 23 are in the Clearfork zone, 58 are in the Spraberry zone, and three are in the Cline zone. These wells have lateral lengths ranging from approximately 4,000 feet to 11,000 feet. In 2016, we expect that our average lateral lengths will be in the range of 7,000 feet to 8,000 feet, although the actual length will vary depending on the layout of our acreage and other factors. As technology improves, we expect that our average lateral lengths will increase, resulting in higher per well recoveries and lower development costs per BOE. During the year ended December 31, 2015, we were able to drill our horizontal wells with approximately 7,500 foot lateral lengths to total depth, or TD, in an average of 13.9 days and we drilled an approximately 10,000 foot lateral well in 14.2 days. Further advances in drilling and completion technology may result in economic development of zones that are not currently viable.

- Leverage our experience operating in the Permian Basin. Our executive team, which has an average of over 25 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. Our focus on efficient drilling and completion techniques is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. We believe that the experience of our executive team in deviated and horizontal drilling and completions has helped reduce the execution risk normally associated with these complex well paths. In addition, our completion techniques are continually evolving as we evaluate and implement hydraulic fracturing practices that have and are expected to continue to increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

- Enhance returns through our low cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. Our acreage position in the Wolfberry play is generally in contiguous blocks which allows us to develop this acreage efficiently with a “manufacturing” strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 96% of our acreage. This operational control allows us to manage more efficiently the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 80% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- Pursue strategic acquisitions with substantial resource potential. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets. During the year ended December 31, 2015, we acquired approximately 16,941 gross (12,672 net) leasehold acres primarily in Howard, Martin, Andrews and Midland counties. We intend to continue to pursue acquisitions that meet our strategic and financial targets.

- Maintain financial flexibility. We seek to maintain a conservative financial position. In connection with our fall 2015 redetermination, the agent lender under our revolving credit agreement recommended a borrowing base of $750.0 million. We elected a commitment amount of $500.0 million, of which $489.0 million was available for borrowing as of December 31, 2015. As of December 31, 2015, Viper had $34.5 million in outstanding borrowings, and $165.5 million available for borrowing, under its revolving credit facility.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- Oil rich resource base in one of North America's leading resource plays. All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Wolfberry play. Our production for the year ended December 31, 2015 was approximately 75% oil, 14% natural gas liquids and 11% natural gas. As of December 31, 2015, our estimated net proved reserves were comprised of approximately 67% oil and 17% natural gas liquids.

- Multi-year drilling inventory in one of North America's leading oil resource plays. We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed price of approximately $40.00 per Bbl WTI, we currently have approximately 1,500 gross (960 net) identified economic potential horizontal drilling locations on our acreage based on our our evaluation of applicable geologic and engineering data. These gross identified economic potential horizontal locations have an average lateral length of approximately 8,375 feet, with the actual length depending on lease geometry and other considerations. These locations exist across most of our acreage blocks and in multiple horizons. Of these 1,500 locations, 840 are in the Wolfcamp B horizon or the Lower Spraberry horizon, with the remaining locations in either the Wolfcamp A, Middle Spraberry, Clearfork, Wolfcamp C or Cline horizons. Our current horizontal location count for the Wolfcamp B horizon is based on 660 foot spacing between wells in all counties except Andrews, Dawson, Upton, and northwest Martin counties where it is 880 foot spacing. For the Lower Spraberry horizon, the horizontal location count is based on 500 foot spacing in the Spanish Trail property in Midland County and 660 foot spacing in other counties except Upton, Dawson and central Andrews counties where it is based on 880 foot spacing. In the Wolfcamp A horizon, the horizontal location count in based on 660 foot spacing in Howard and Glasscock counties, 880 foot spacing in Midland and southwest Martin counties and 1,320 foot spacing in other counties. Middle Spraberry counts are based on 880 foot spacing in Midland, Martin and northeast Andrews counties and 1,320 foot spacing in other counties. The horizontal location counts for the Cline, Clearfork and Wolfcamp C horizons are based on 1,320 spacing except for the Clearfork in central Andrews County which is based on 660 foot spacing. The ultimate inter-well spacing may vary from these distances due to different factors, which would result in a higher or lower location count. The two-stream gross estimated ultimate recoveries, or EURs, from our future PUD horizontal wells, as estimated by Ryder Scott as of December 31, 2015, range from 392 MBOE per well, consisting of 280 MBbls of oil and 673 MMcf of natural gas, to 1,318 MBOE per well, consisting of 1,035 MBbls of oil and 1,698 MMcf of natural gas, for wells ranging in lateral length from approximately 5,000 feet to approximately 10,000 feet, in intervals including the Clearfork, Middle Spraberry, Lower Spraberry, Wolfcamp A, and Wolfcamp B. Ryder Scott has estimated gross EURs of 635 MBOE for our Wolfcamp B wells in Midland County and 990 MBOE for our Lower Spraberry wells in Midland County, which constitute 54% of our remaining PUD horizontal wells, in each case based on 7,500 foot lateral lengths. In addition, we have approximately 698 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including additional horizontal drilling opportunities and strategic leasehold acquisitions.

- Experienced, incentivized and proven management team. Our executive team has an average of over 25 years of industry experience per person, most of which is focused on resource play development. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal wells as well as horizontal well reservoir and geologic expertise, which is of strategic importance as we expand our horizontal drilling activity. Prior to joining us, our Chief Executive Officer held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources.

- Favorable operating environment. We have focused our drilling and development operations in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. We believe that the geological and regulatory environment of the Permian Basin is more stable and predictable, and that we are faced with less operational risks, in the Permian Basin as compared to emerging hydrocarbon basins.

- High degree of operational control. We are the operator of approximately 96% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to increase or decrease our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Our Properties

Location and Land

Our total net acreage position in the Permian Basin was approximately 84,683 net acres at December 31, 2015. We are the operator of approximately 96% of this Permian Basin acreage. In addition, we, through our subsidiary Viper, own mineral interests underlying approximately 46,562 gross (17,060 net) acres primarily in Midland County, Texas in the Permian Basin. Approximately 60% of these net acres are operated by us. Since our initial acquisition in the Permian Basin through December 31, 2015, we drilled or participated in the drilling of 490 gross (407 net) wells on our leasehold acreage in this area, primarily targeting the Wolfberry play. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States.

Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties. Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

During the late 1990s, Atlantic Richfield Company, or Arco, began a drilling program targeting the base of the Spraberry formation at 10,000 feet, with an additional 200 to 300 feet drilled to produce from the upper portion of the Wolfcamp formation. Henry Petroleum, a private firm, owned interests in the Pegasus field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracturing treatments across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum’s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum’s program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they monetized a portion of their acreage position, which led to the acquisition that enabled us to begin our participation in this play. Recent advancements in enhanced recovery techniques and horizontal drilling continue to make this play attractive to the oil and gas industry. By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Wolfberry play. As of December 31, 2015, we held working interests in 918 gross (732) net producing wells.

Geology

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita fold belt. It is one of the largest sedimentary basins in the U.S., and has oil and gas production from several reservoirs from Permian through Ordovician in age. The term “Wolfberry” was coined initially to indicate commingled production from the Permian Spraberry, Dean and Wolfcamp formations. In this report, we refer to the Clearfork, Spraberry, Wolfcamp, Strawn and Atoka formations collectively as the Wolfberry play. The Wolfberry play of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging Wolfcamp play.

The Spraberry was deposited as turbidites in a deep water submarine fan environment, while the Wolfcamp reservoirs consist of debris-flow and grain-flow sediments, which were also deposited in a submarine fan setting. The best carbonate reservoirs within the Wolfcamp are generally found in proximity to the Central Basin Platform, while the shale reservoirs within the Wolfcamp thicken basinward away from the Central Basin Platform. Both the Spraberry and Wolfcamp contain organic-rich mudstones and shales which, when buried to sufficient depth for maturation, became the source of the hydrocarbons found both within the shales themselves and in the more conventional clastic and carbonate reservoirs between the shales. The Wolfberry is an unconventional “basin-centered oil” resource play, in the sense that there is no regional downdip oil/water contact.

We have successfully developed several shale intervals within the Clearfork, Spraberry and Wolfcamp formations since we began horizontal drilling in 2012. The shales exhibit micro-darcy permeabilities which result in relatively small drainage areas and recovery factors, so relatively small inter-well spacing is necessary.

We possess, or are in the process of acquiring, 3-D seismic data over substantially all of our major asset areas. Our extensive geophysical database currently includes approximately 698 square miles of 3-D data, and we are in the process of acquiring an additional 19 square miles. This data will continue to be utilized in the development of our horizontal drilling activities and to identify and avoid potential geohazards (e.g., faults and lithologies that are difficult to drill).

Production Status

During the year ended December 31, 2015, net production from our Permian Basin acreage was 12,080,631 BOE, or an average of 33,098 BOE/d, of which approximately 75% was oil, 14% was natural gas liquids and 11% was natural gas.

Facilities

Our oil and natural gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/natural gas/water separation equipment and pumping units.

Future Activity

During 2016, we expect to drill an estimated 30 to 70 gross (25 to 58 net) horizontal wells on our acreage. We currently estimate that our capital expenditures for 2016 will be between $250.0 million and $375.0 million, consisting of $210.0 million to $315.0 million for horizontal drilling and completions, $25.0 million to $35.0 million for infrastructure and $15.0 million to $25.0 million for non-operated activity and other expenditures, but excluding the cost of any leasehold and mineral rights acquisitions. During the year ended December 31, 2015, we drilled 64 gross (54 net) and completed 65 gross (54 net) horizontal wells. We drilled and completed four gross (three net) vertical wells and participated in the drilling of 15 gross (six net) non-operated wells in the Permian Basin. During the year ended December 31, 2015, our capital expenditures for drilling, completing and equipping wells was $358.0 million. We spent $27.0 million for oil and gas infrastructure and $34.0 million for non-operated properties. We spent an additional $481.4 million for leasehold and mineral rights acquisitions.

We intend to release one of our three horizontal drilling rigs in March 2016. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans as conditions warrant. We are prepared to decelerate our drilling program if commodity prices deteriorate and accelerate our drilling program if commodity prices improve. We have the option to release a second rig in the second quarter of 2016 and continue to operate one rig.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2015, 2014 and 2013 were prepared by Ryder Scott with respect to our assets and those of Viper. Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2015 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 90% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 10% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve reports to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our Vice President–Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Vice President–Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 24 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Vice President–Reservoir Engineering or under his direct supervision;
- review by our Vice President–Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Vice President–Reservoir Engineering to our Chief Executive Officer;
- verification of property ownership by our land department; and

- no employee’s compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2015, 2014 and 2013 (including those attributable to Viper), based on the reserve reports prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

	December 31,		
	2015	2014	2013
Estimated proved developed reserves:			
Oil (Bbls)	60,569,398	43,885,835	19,789,965
Natural gas (Mcf)	96,871,109	68,264,113	31,428,756
Natural gas liquids (Bbls)	15,418,353	11,221,428	4,973,493
Total (BOE)	92,132,936	66,484,615	30,001,584
Estimated proved undeveloped reserves:			
Oil (Bbls)	45,409,313	31,803,754	22,810,887
Natural gas (Mcf)	52,631,635	43,341,147	30,250,740
Natural gas liquids (Bbls)	10,585,791	7,320,504	5,732,231
Total (BOE)	64,767,043	46,347,783	33,584,908
Estimated Net Proved Reserves:			
Oil (Bbls)	105,978,711	75,689,589	42,600,852
Natural gas (Mcf)	149,502,744	111,605,260	61,679,496
Natural gas liquids (Bbls)	26,004,144	18,541,932	10,705,724
Total (BOE)(1)	156,899,979	112,832,398	63,586,492
Percent proved developed	58.7 %	58.9 %	47.2 %

(1) Estimates of reserves as of December 31, 2015, 2014 and 2013 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2015, 2014 and 2013, respectively, in accordance with SEC guidelines applicable to reserves estimates as of the end of such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A."Risk Factors." We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, our proved undeveloped reserves totaled 45,409 MBbls of oil, 52,632 MMcf of natural gas and 10,586 MBbls of natural gas liquids, for a total of 64,767 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table includes the changes in PUD reserves for 2015:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2014	46,348
Undeveloped reserves transferred to developed	(13,680)
Revisions	(12,656)
Extensions and discoveries	44,755
Ending proved undeveloped reserves at December 31, 2015	64,767

The increase in proved undeveloped reserves was primarily attributable to extensions of 44,755 MBOE from continued successful horizontal development of the Lower Spraberry and Wolfcamp B horizons and initial development of the Wolfcamp A and Middle Spraberry intervals on our acreage. Approximately 63% of the extensions are classified as proved undeveloped. Approximately 20% of the proved undeveloped reserve extensions are associated with well locations that are more than one offset away from existing producing wells. All of these locations are within 1,700 feet of producing wells. Partially offsetting the increase in proved undeveloped reserves were decreases due to technical revisions. Downward revisions of approximately 12,656 MBOE were a result of reclassifying 14,619 MBOE of reserves attributable to 80 vertical wells and 22 horizontal wells in which we have a working interest and 22 vertical wells in which we have only a mineral interest held through Viper due to lower product prices. Vertical well reclassifications accounted for 8,607 MBOE of the total of 14,619 MBOE. These vertical locations were also unlikely to be developed within the five-year period required by the applicable SEC rules (even if commodity prices recover) due to our focus on horizontal well development. As of December 31, 2015, horizontal wells represented approximately 99.7% of our PUD locations.

Costs incurred relating to the development of PUDs were approximately $42.7 million during 2015. Estimated future development costs relating to the development of PUDs are projected to be approximately $134.0 million in 2016, $174.0 million in 2017, $136.0 million in 2018 and $36.0 million in 2019. Since our current executive team assumed management control in 2011, our average drilling costs and drilling times have been reduced. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

Our December 31, 2015 proved reserves were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December 2015 of $50.28 per Bbl and $2.58 per MMBtu. Holding production and development costs constant, if SEC pricing had been the December 31, 2015 pricing of $37.04 per Bbl and $2.34 per MMbtu, this would have resulted in a decrease of 20,005 MBOE of our estimated PUD reserves.

As of December 31, 2015, all of our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

As of December 31, 2015, less than 1.0% of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and natural gas liquids, all of which is from the Permian Basin in West Texas, and certain price and cost information for each of the periods indicated:

	Historical Year Ended December 31,		
	2015	2014	2013
Production Data:			
Oil (Bbls)	9,081,135	5,381,576	2,022,749
Natural gas (Mcf)	7,931,237	4,345,916	1,730,497
Natural gas liquids (Bbls)	1,677,623	1,001,991	361,079
Combined volumes (BOE)	12,080,631	7,107,886	2,672,244
Daily combined volumes (BOE/d)	33,098	19,474	7,321
Average Prices:			
Oil (per Bbl)	$44.68	$83.48	$93.32
Natural gas (per Mcf)	2.47	4.15	3.61
Natural gas liquids (per Bbl)	12.77	28.39	36.00
Combined (per BOE)	36.98	69.74	77.84
Oil, hedged($ per Bbl)(1)	60.63	85.42	89.75
Average price, hedged($ per BOE)(1)	48.97	71.21	75.14
Average Costs per BOE:			
Lease operating expense	$6.84	$7.79	$7.92
Production and ad valorem taxes	2.73	4.59	4.83
Gathering and transportation expense	0.50	0.46	0.34
General and administrative - cash component	1.11	1.61	3.47
Total operating expense - cash	11.18	14.45	16.56
General and administrative - non-cash component	1.54	1.38	0.66
Depreciation, depletion, and amortization	18.02	23.92	24.92
Interest expense	3.44	4.86	3.02
Total expenses	23.00	30.16	28.60

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

Productive Wells

As of December 31, 2015, we owned an average unweighted 80% working interest in 1,029 gross (820 net) productive wells. Through our subsidiary Viper, we own an average unweighted 19% royalty or mineral interest in 130 additional productive wells in which we do not own a working interest. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage

The following table sets forth information as of December 31, 2015 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage(3)	
Basin	Gross(4)	Net(5)	Gross(4)	Net(5)	Gross(4)	Net(5)
Permian	65,119	62,763	40,150	21,920	105,269	84,683

(1) Developed acres are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) Does not include Viper's mineral interests but does include 22,500 gross (16,811 net) leasehold acres that we own underlying our mineral interests.

(4) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(5) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped acreage expirations

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2015, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2016		2017		2018		2019		2020	
Basin	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian	15,305	6,007	23,312	15,142	—	—	—	—	31	21

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. Each of these wells was drilled in the Permian Basin of West Texas. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	8	6	40	31	52	43
Dry	—	—	—	—	—	—
Exploratory:						
Productive	71	57	53	43	31	26
Dry	—	—	—	—	—	—

Total:						
Productive	79	63	93	74	83	69
Dry	—	—	—	—	—	—

As of December 31, 2015, we had 44 gross (34 net) wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the above table.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Marketing and Customers

We typically sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (59%); and Enterprise Crude Oil LLC (15%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%); and Enterprise Crude Oil LLC (16%). For the year ended December 31, 2013, two purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, based on the current demand for oil and natural gas, and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

On May 24, 2012, we entered into an oil purchase agreement with Shell Trading (US) Company, in which we agreed to sell specified quantities of oil to Shell Trading (US) Company upon completion of the reversal of the Magellan Longhorn pipeline and its conversion for oil shipment, which occurred on October 1, 2013. Our agreement with Shell Trading (US) Company has an initial term of five years from the completion date. The agreement may also be terminated by Shell Trading (US) Company by written notice to us in the event that Shell Trading (US) Company's contract for transportation on the pipeline is terminated. Our maximum delivery obligation under this agreement is 8,000 gross barrels per day. We have a one-time right to elect to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased contract quantity will be effective for the remainder of the term of the agreement. Shell Trading (US) Company has agreed to pay to us the price per barrel of oil based on the arithmetic average of the daily settlement price for "Light Sweet Crude Oil" Prompt Month future contracts reported by the NYMEX over the one-month period, as adjusted based on adjustment formulas specified in the agreement. If we fail to deliver the required quantities of oil under the agreement during any three-month period following the service commencement date, we have agreed to pay Shell Trading (US) Company a deficiency payment, which is calculated by multiplying (i) the volume of oil that we failed to deliver as required under the agreement during such period by (ii) Magellan's Longhorn Spot tariff rate in effect for transportation from Crane, Texas to the Houston Ship Channel for the period of time for which such deficiency volume is calculated.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Transportation

During the initial development of our fields we evaluate all gathering and delivery infrastructure in the areas of our production. Currently, a majority of our production is transported to the purchaser by pipeline, which we anticipate will increase to approximately 90% for oil by the end of 2016.

During 2015, several oil and saltwater disposal gathering systems were installed. At December 31, 2015, approximately 83% of our produced water was connected to saltwater disposals by pipe and approximately 67% of our oil production was sold by pipe. These initiatives reduced the cost of the water which was being trucked to disposal by approximately $1.43/bbl and reduced the transportation cost of the oil being sold by truck by $0.75/bbl. We believe that these gathering systems will help us reduce our lease operating expense and improve our margins on sales in future periods.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 18.75% to 25.00%, resulting in a net revenue interest to us generally ranging from 81.25% to 75.00%.

Seasonal Nature of Business

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Regulation

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

Environmental Matters and Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. Liability under such laws and regulations is strict (i.e., no showing of “fault” is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of the Resource Conservation and Recovery Act, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under the Resource Conservation and Recovery Act, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, which we refer to as CERCLA or the “Superfund” law, and analogous state laws, generally imposes liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” are subject to strict liability that, in some circumstances, may be joint and several for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works, or POTW, which regulations are discussed in more detail below under the caption "–Regulation of Hydraulic Fracturing." Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The Oil Pollution Act contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The Oil Pollution Act subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or the Oil Pollution Act may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below in "–Regulation of Hydraulic Fracturing." These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources of emissions such as power plants or industrial facilities. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of greenhouse gases from motor vehicles. The EPA adopted the stationary source rule, which we refer to as the tailoring rule, in May 2010, and it became effective January 2011. The tailoring rule established new greenhouse gas emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their greenhouse gas emissions. The Court ruled, however, that the EPA may require installation of best available control technology for greenhouse gas emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on greenhouse gas permitting requirements in response to the Court's decision in Utility Air Regulatory Group v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to greenhouse gases in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S., including natural gas liquids fractionators and local natural gas distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded the greenhouse gas reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the greenhouse gas reporting rule to add the reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt greenhouse gas regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the

Clean Power Plan in the D.C. Circuit Court of Appeals. As a result of this continued regulatory focus, future greenhouse gas regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of greenhouse gases. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely affect the oil and natural gas industry. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. Furthermore, legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress.

In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to POTW. The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSP standards. Further, on July 31, 2015, the EPA finalized two updates to the NSP standards to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and volatile organic compound emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. We cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation, effective September 1, 2011, requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. The Texas Railroad Commission adopted rules and regulations implementing this legislation that apply to all wells for which the Texas Railroad Commission issues an initial drilling permit after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of OSHA for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Also, in May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;

- the method of drilling and casing wells;

- the timing of construction or drilling activities, including seasonal wildlife closures;

- the rates of production or “allowables”;

- the surface use and restoration of properties upon which wells are drilled;

- the plugging and abandoning of wells; and

- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in “first sales,” which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC’s current regulatory regime, transmission services are provided on an open-access, non-discriminatory basis at cost-based rates or negotiated rates. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Operational Hazards and Insurance

The oil and natural gas industry involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for onshore property (oil lease property/production equipment) for selected locations, rig physical damage protection, control of well protection for selected wells, comprehensive general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverage.

Our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. See Item 1A. “Risk Factors–Risks Related to the Oil and Natural Gas Industry and Our Business–Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.”

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider’s employees as well as contractors and subcontractors hired by the service provider.

Employees

As of December 31, 2015, we had approximately 141 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Facilities

Our corporate headquarters is located in Midland, Texas. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. We believe that our facilities are adequate for our current operations.

Availability of Company Reports

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports are available free of charge on the Investor Relations page of our website at www.diamondbackenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission. Information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in Item 1. “Business” and Item 7A. “Quantitative and Qualitative Disclosures About Market Risk.” These risks are not the only risks we face. We could also face additional risks and uncertainties not currently known to the Company or that we currently deem to be immaterial. If any of these risks actually occurs, it could materially harm our business, financial conditional or results of operations and the trading price of our shares could decline.

Risks Related to the Oil and Natural Gas Industry and Our Business

Market conditions for oil and natural gas, and particularly the ongoing decline in prices for oil and natural gas have, and may continue to, adversely affect our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;

- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $34.55 per barrel, or Bbl, in December 2015

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to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.63 per MMBtu in January 2016 to a high of $8.15 per MMBtu in February 2014. During 2015, WTI prices ranged from $34.55 to $61.36 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.63 to $3.32 per MMBtu. On January 20, 2016, the WTI posted price for crude oil was $26.68 per Bbl and the Henry Hub spot market price of natural gas was $2.28 per MMBtu, representing decreases of 57% and 31%, respectively, from the high of $61.36 per Bbl of oil and $3.32 per MMBtu for natural gas during 2015. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected.

In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have precipitated an economic slowdown. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish further, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

A significant portion of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

A significant portion of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our development and exploration operations and our ability to complete acquisitions require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. In 2015, our total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $900.9 million. Our 2016 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $250.0 million to $375.0 million, representing a decrease of 26% over our 2015 capital budget. Since completing our initial public offering in October 2012, we have financed capital expenditures primarily with borrowings under our revolving credit facility, cash generated by operations and the net proceeds from public offerings of our common stock and the senior notes.

We intend to finance our future capital expenditures with cash flow from operations, proceeds from offerings of our debt and equity securities and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;

- the volume of oil and natural gas we are able to produce from existing wells;

- the prices at which our oil and natural gas are sold;

- our ability to acquire, locate and produce economically new reserves; and

- our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2016 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made, and expect to make in the future, substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. We may not have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. If we are unable to replace our current production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;

- future oil and natural gas prices and their applicable differentials;

- operating costs; and

- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. The inability to effectively manage the integration of acquisitions, including our recently completed and pending acquisitions, could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. From inception through December 31, 2015, we drilled a total of 448 gross wells and participated in an additional 42 gross non-operated wells, of which 446 wells were completed as producing wells and 44 wells were in various stages of completion. If future wells or the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected.

Our identified potential drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

At an assumed price of approximately $40.00 per Bbl WTI, we currently have approximately 1,500 gross (960 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage. As of December 31, 2015, only 107 of our gross identified potential horizontal drilling locations and three of our identified vertical drilling locations were attributed to proved reserves. These drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results and the availability of water. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. In addition, we have identified approximately 690 horizontal drilling locations in intervals in which we have drilled very few or no wells, which are necessarily more speculative and based on results from other operators whose acreage may not be consistent with ours. We cannot predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. While through December 31, 2015, we are the operator of or have participated in a total of 184 horizontal wells completed on our acreage, we cannot assure you that the analogies we draw from available data from these or other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Multi-well pad drilling may result in volatility in our operating results.
We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.
Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2015, we had leases representing 6,007 net acres expiring in 2016, 15,142 net acres expiring in 2017, no net acres expiring in 2018, no net acres expiring in 2019 and 21 net acres expiring in 2020. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases expiring in 2016, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs in this time frame, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.

We have entered into price swap derivatives and may in the future enter into forward sale contracts or additional price swap derivatives for a portion of our production. Although we have hedged a portion of our estimated 2016 production, we may still be adversely affected by continuing and prolonged declines in the price of oil.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. Under these swap contracts, we receive a fixed price per barrel of oil and pay a floating market price per barrel of oil to the counterparty based on Inter-Continental Exchange, or ICE, pricing for Brent crude oil. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. These contracts and any future economic hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase.

As of December 31, 2015, we had crude oil swap contracts in place covering ICE Brent crude oil priced at a weighted average price of $88.72 for 91,000 aggregate Bbls for the production period of January through February 2016. As of February 17, 2016, we had not entered into any significant hedging transactions with respect to our anticipated 2016 production. To the extent that the price of oil remains at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

Our derivative transactions expose us to counterparty credit risk.

Our derivative transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

If production from our Permian Basin acreage decreases due to decreased developmental activities, production related difficulties or otherwise, we may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contract, which will result in deficiency payments to the counterparty and may have an adverse effect on our operations.

We are a party to an agreement with Shell Trading (US) Company under which we are obligated to deliver specified quantities of oil to Shell Trading (US) Company. Our maximum delivery obligation under this agreement is 8,000 gross barrels per day. We have a one-time right to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased quantity will be effective for the remainder of the term of the agreement. If production from our Permian Basin acreage decreases due to decreased developmental activities, as a result of the low commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under the oil purchase agreement, which may result in deficiency payments to the counterparty and may have an adverse effect on our operations.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through receivables from joint interest owners on properties we operate (approximately $41.3 million at December 31, 2015) and receivables from purchasers of our oil and natural gas production (approximately $37.6 million at December 31, 2015). Joint interest receivables arise from billing 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 wish to drill. We are generally unable to control which co-owners participate in our wells.

We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (59%); and Enterprise Crude Oil LLC (15%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%); and Enterprise Crude Oil LLC (16%). For the year ended December 31, 2013, two purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. We do not require our customers to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results.

Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $17.84, $23.79 and $24.63 for the years ended December 31, 2015, 2014 and 2013, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the years ended December 31, 2015, 2014 and 2013 was $216.1 million, $168.7 million and $65.8 million, respectively.

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. Beginning December 31, 2009, we have used the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.

An impairment on proved oil and natural gas properties of $814.8 million was recorded for the year ended December 31, 2015. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2014 and 2013. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations–Critical Accounting Policies and Estimates–Method of accounting for oil and natural gas properties” for a more detailed description of our method of accounting. If prices of oil, natural gas and natural gas liquids continue to decline, we may be required to further write down the value of our oil and natural gas properties, which could negatively affect our results of operations.

Our estimated reserves and EURs are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Our historical estimates of proved reserves as of December 31, 2015, 2014 and 2013 (which include those attributable to Viper) are based on reports prepared by Ryder Scott, which conducted a well-by-well review of all our properties for the periods covered by its reserve reports using information provided by us. The EURs for our horizontal wells are based on management’s internal estimates. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that we ultimately recover being different from our reserve estimates. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The estimates of reserves as of December 31, 2015, 2014 and 2013 included in this report were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods December 31, 2015, 2014 and 2013, respectively, in accordance with the SEC guidelines applicable to reserve estimates for such periods. Commodity prices have deteriorated significantly since that time, and accordingly, using more recent prices in estimating our proved reserves, without giving effect to any acquisition or development activities we have executed during 2016, would result in a reduction in proved reserve volumes due to economic limits.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves.

The standardized measure of our estimated proved reserves and our PV-10 are not necessarily the same as the current market value of our estimated proved oil reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, and our related PV-10 calculation, may not represent the current market value of our estimated proved oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, "Extractive Activities–Oil and Gas," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe because they have become uneconomic or otherwise.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 41.3% of our total estimated proved reserves as of December 31, 2015, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or further decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

In addition to the geographic concentration of our producing properties described above, as of December 31, 2015, all of our proved reserves were attributable to the Wolfberry play. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (59%); and Enterprise Crude Oil LLC (15%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading

(US) Company (64%); and Enterprise Crude Oil LLC (16%). For the year ended December 31, 2013, two purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production. The loss of one or more of these customers, and our inability to sell our production to other customers on terms we consider acceptable, could materially and adversely affect our business, financial condition, results of operations and cash flow.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing rigs, and the operator of those rigs may choose to cease providing services to us. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. Over the past several years, Texas has experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, or we are unable to effectively utilize flowback water, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Our business is difficult to evaluate because we have a limited operating history.

Diamondback Energy, Inc. commenced business operations on October 11, 2012. Prior to that time, all of our historical oil and natural gas assets, operations and results described in this report were those of Windsor Permian LLC and Windsor UT LLC. In connection with our initial public offering, Windsor Permian LLC became our wholly-owned subsidiary and we acquired the oil and natural gas assets of Gulfport Energy Corporation located in the Permian Basin. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

We commenced business operations in October 2012 and growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

We have incurred losses from operations during certain periods since our inception and may do so in the future.

Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from our operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the new techniques we are adopting, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering system. Our purchasers then transport the oil by truck to a pipeline for transportation. Our natural gas production is generally transported by our gathering lines from the wellhead to an interconnection point with the purchaser. We do not control these trucks and other third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. For example, on certain occasions we have experienced high line pressure at our tank batteries with occasional flaring due to the inability of the gas gathering systems in the areas in which we operate to support the increased production of natural gas in the Permian Basin. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. See Item 1. “Business–Regulation” for a description of certain laws and regulations that affect us.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. Furthermore, legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress.

In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to POTW. The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For a more detailed discussion of state and local laws and initiatives concerning hydraulic fracturing, see "Items 1 and 2. Business and Properties–Regulation–Regulation of Hydraulic Fracturing." We use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S. Congress adopted the Dodd Frank Wall Street Reform and Consumer Protection Act, or Dodd-Frank Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010. In its rulemaking under the legislation, the Commodities Futures Trading Commission has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The Commodities Futures Trading Commission’s final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the Commodities Futures Trading Commission to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the Commodities Futures Trading Commission has indicated that it intends to appeal the court’s decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the Commodities Futures Trading Commission will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

From time to time, legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, but are not limited to, (i) eliminating the immediate deduction for intangible drilling

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and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, (iii) the repeal of the percentage depletion allowance for oil and natural gas properties; (iv) an extension of the amortization period for certain geological and geophysical expenditures and (v) implementing certain international tax reforms. Further, in February 2016, the President's administration issued a proposed budget, which includes, among other things, a proposed tax of $10.25 per barrel equivalent on petroleum products.

These proposed changes in the U.S. tax law, if adopted, or other similar changes that tax our production or reduce or eliminate deductions currently available with respect to natural gas and oil exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. While we are subject to certain federal greenhouse gas monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed greenhouse gas rules and regulations, see "Items 1 and 2. Business and Properties–Regulation–Environmental Regulation-Climate Change."
In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely affect the oil and natural gas industry. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 exempts natural gas gathering facilities from regulation by the FERC. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore are exempt from FERC's jurisdiction under the Natural Gas Act of 1938. However, the distinction between FERC–regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Our operations and drilling activity are concentrated in the Permian Basin in West Texas, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could lead to a reduction in production volumes. Any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our business, financial condition and results of operations.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team, including our Chief Executive Officer, Travis D. Stice, could disrupt our operations. We have employment agreements with these executives which contain restrictions on competition with us in the event they cease to be employed by us. However, as a practical matter, such employment agreements may not assure the retention of our employees. Further, we do not maintain “key person” life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;

- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

Historically, we have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks and ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations.

We endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under our agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors' equipment while in their control and (ii) we generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we generally agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operations.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable.

A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Increased costs of capital could adversely affect our business.

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We recorded stock-based compensation expense in 2015, 2014 and 2013, and we may incur substantial additional compensation expense related to our future grants of stock compensation which may have a material negative impact on our operating results for the foreseeable future.

As a result of outstanding stock-based compensation awards, for the years ended December 31, 2015, 2014 and 2013 we incurred $24.6 million, $14.3 million and $2.7 million, respectively, of stock based compensation expense, of which we capitalized $6.0 million, $4.4 million and $1.0 million respectively, pursuant to the full cost method of accounting for oil and natural gas properties. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and possible future incentive plans. These additional expenses could adversely affect our net income. The future expense will be dependent upon the number of share-based awards issued and the fair value of the options or shares of common stock at the date of the grant; however, they may be significant. We will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of its vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of our business.

Risks Related to Our Indebtedness

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the senior notes and our other indebtedness.

As of December 31, 2015, we had total long-term debt of $495.5 million, including $450.0 million outstanding under the senior notes, and we had unused borrowing base availability of $489.0 million under our revolving credit facility. As of

December 31, 2015, Viper, one of our subsidiaries, had $34.5 million in outstanding borrowings, and $165.5 million available for borrowing, under its revolving credit facility. We may in the future incur significant additional indebtedness under our revolving credit facility or otherwise in order to make acquisitions, to develop our properties or for other purposes. Our level of indebtedness could have important consequences to you and affect our operations in several ways, including the following:

- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to the senior notes, including any repurchase obligations that may arise thereunder;
- a significant portion of our cash flows could be used to service the senior notes and our other indebtedness, which could reduce the funds available to us for operations and other purposes;
- a high level of debt could increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also limit management’s discretion in operating our business and our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings;
- a high level of debt could limit our ability to access the capital markets to raise capital on favorable terms;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- we may be vulnerable to interest rate increases, as our borrowings under our revolving credit facility are at variable interest rates.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

Restrictive covenants in our revolving credit facility, the indenture governing the senior notes and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.

Our revolving credit facility and the indenture governing the senior notes contain, and the terms of any future indebtedness may contain, restrictive covenants that limit our ability to, among other things:

- incur or guarantee additional indebtedness;
- make certain investments;
- create additional liens;
- sell or transfer assets;
- issue preferred stock;
- merge or consolidate with another entity;
- pay dividends or make other distributions;

- designate certain of our subsidiaries as unrestricted subsidiaries;
- create unrestricted subsidiaries;
- engage in transactions with affiliates; and
- enter into certain swap agreements.

In connection with the closing of Viper's initial public offering on June 23, 2014, we entered into an amendment to our revolving credit facility, which modified certain provisions of our revolving credit facility to allow us, among other things, to designate one or more of our subsidiaries as "unrestricted subsidiaries" that are not subject to certain restrictions contained in the revolving credit facility. Under the amended revolving credit facility, we designated Viper, the general partner and Viper's subsidiary as unrestricted subsidiaries, and upon such designation, they were automatically released from any and all obligations under the amended revolving credit facility, including the related guaranty, and all liens on the assets of, and the equity interests in, Viper, the general partner and Viper's subsidiary under the amended revolving credit facility were automatically released. Further, in connection with the closing of Viper's initial public offering, we designated Viper, the general partner and Viper's subsidiary as unrestricted subsidiaries under the indenture governing the senior notes and upon such designation, Viper Energy Partners LLC, which was a guarantor under the indenture governing the senior notes prior to such designation, was released as a guarantor under the indenture governing the senior notes.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our revolving credit facility and the indenture governing the senior notes. In addition, our revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

A breach of any of these restrictive covenants could result in default under our revolving credit facility. If default occurs, the lenders under our revolving credit facility may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due and payable, which would result in an event of default under the indenture governing the senior notes. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay outstanding borrowings when due, the lenders under our revolving credit facility will also have the right to proceed against the collateral granted to them to secure the indebtedness. If the indebtedness under our revolving credit facility and the senior notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

Availability under our revolving credit facility is currently subject to a borrowing base of $750.0 million, of which we have elected a commitment amount of $500.0 million. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. As of December 31, 2015, we had outstanding borrowings of $11.0 million which bore a weighted average interest rate of 1.92%. We intend to continue borrowing under our revolving credit facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further if, the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we would be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Servicing our indebtedness requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial indebtedness.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness, including the senior notes, depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. In the absence of such cash flows, we could have substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our revolving credit facility and the indenture governing the senior notes restrict our ability to use the proceeds from asset sales. We may not be able to consummate those asset sales to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on our financial condition.

We may still be able to incur substantial additional indebtedness in the future, which could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our revolving credit facility and the indenture governing the senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2015, our borrowing base under our revolving credit facility was set at $750.0 million, of which we have elected a commitment amount of $500.0 million and we had outstanding borrowings of $11.0 million under this facility. As of December 31, 2015, Viper had $34.5 million in outstanding borrowings, and $165.5 million available for borrowing, under its revolving credit facility. In addition, the indenture governing the senior notes allows us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indenture governing the senior notes also allows us to incur certain other additional secured debt and allows us to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to the senior notes. In addition, the indenture governing the senior notes does not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

Borrowings under our and Viper’s revolving credit facilities expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings 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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. As of December 31, 2015, we had $11.0 million in borrowings outstanding under our revolving credit facility. Our weighted-average interest rate on borrowings from our revolving credit facility was 1.92% during the year ended December 31, 2015. Viper's weighted average interest rate on borrowings from its revolving credit facility was 1.70% during the year ended December 31, 2015. As of December 31, 2015, Viper, one of our subsidiaries, had $34.5 million in outstanding borrowings, and $165.5 million available for borrowing, under its revolving credit facility. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Risks Related to Our Common Stock

The corporate opportunity provisions in our certificate of incorporation could enable Wexford, our equity sponsor prior to our initial public offering, or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;

- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and

- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

Wexford continues to own shares of our common stock, and its interests may conflict with those of our other stockholders.

As of February 12, 2016, Wexford beneficially owned less than 1% of our common stock. In addition, an individual affiliated with Wexford serves as the Chairman of our Board of Directors. As a result, Wexford may be able to exercise influence over matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. The interests of Wexford with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders’ best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. These transactions include, among others, drilling services provided to us by Bison, real property leased by us from Fasken Midland, LLC, and hydraulic fracturing sand purchased by us from Muskie. Each of these entities is either controlled by or affiliated with Wexford, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders’ best interests because Wexford may have the ability to influence the outcome of these conflicts.

We incur increased costs as a result of being a public company, which may significantly affect our financial condition.

We completed our initial public offering in October 2012. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations increase our legal and financial compliance costs and make some activities more time-consuming and costly. These rules and regulations make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

If the price of our common stock fluctuates significantly, your investment could lose value.

Although our common stock is listed on the NASDAQ Select Global Market, we cannot assure you that an active public market will continue for our common stock. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or “float” for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. Furthermore, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including:

- our quarterly or annual operating results;
- changes in our earnings estimates;
- investment recommendations by securities analysts following our business or our industry;
- additions or departures of key personnel;
- changes in the business, earnings estimates or market perceptions of our competitors;
- our failure to achieve operating results consistent with securities analysts' projections;
- changes in industry, general market or economic conditions; and
- announcements of legislative or regulatory changes.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

Future sales of our common stock, or the perception that such future sales may occur, may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of such shares, or the perception that such sales may occur, could impair our ability to raise capital through the sale of additional common or preferred stock. Except for any shares purchased by our affiliates, all of the shares of common stock sold in our initial public offering and our subsequent equity offering are freely tradable. In the event that one or more of our stockholders sells a substantial amount of our common stock in the public market, or the market perceives that such sales may occur, the price of our stock could decline.

A change of control could limit our use of net operating losses.

As of December 31, 2015, we had a net operating loss, or NOL, carry forward of approximately $82.6 million for federal income tax purposes. Transfers of our stock could result in an ownership change. In such a case, our ability to use the NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrade our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders;
- limitations on the ability of our stockholders to call a special meeting and act by written consent;
- the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

We do not intend to pay cash dividends on our common stock in the foreseeable future and, therefore, only appreciation of the price of our common stock will provide a return to our stockholders.

We have not paid dividends since our inception and we currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our revolving credit facility prohibit us from paying dividends and making other distributions. As a result, only appreciation of the price of our common stock, which may not occur, will provide a return to our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. 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 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Price Range of Common Stock
Our common stock is listed on the NASDAQ Global Select Market under the symbol “FANG”.

The following table sets forth the range of high and low sales prices of our common stock for the periods presented:

	High	Low
2015		
1st Quarter	$78.75	$55.53
2nd Quarter	$85.82	$73.36
3rd Quarter	$77.36	$60.28
4th Quarter	$82.19	$61.51
2014		
1st Quarter	$70.99	$44.02
2nd Quarter	$93.33	$64.05
3rd Quarter	$90.48	$70.66
4th Quarter	$76.94	$51.69

Holders of Record
There were four holders of record of our common stock on February 16, 2016.

Dividend Policy
We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility restrict the payment of cash dividends on our common stock. See Item 1A. “Risk Factors–Risks Related to the Oil and Natural Gas Industry and Our Business–Our revolving credit facility contains restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.” and Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Credit Facility.” We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Recent Sales of Unregistered Securities
None.

Repurchases of Equity Securities
None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical combined consolidated financial data. The selected historical combined consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report on Form 10-K.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2015, 2014 and 2013 and the balance sheet data as of December 31, 2015 and 2014 are derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The historical financial data for the year ended December 31, 2012 and 2011 and the balance sheet data as of December 31, 2013, 2012 and 2011 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	Year Ended December 31,				
(In thousands, except per share amounts)	2015	2014	2013	2012[1]	2011[2]
Statements of Operations Data:					
Total revenues	$446,733	$495,718	$208,002	$74,962	$49,366
Total costs and expenses	1,187,002	283,048	112,808	57,655	34,219
Income from operations	(740,269)	212,670	95,194	17,307	15,147
Other income (expense)	(8,831)	92,286	(8,853)	1,075	(15,533)
Income (loss) before income taxes	(749,100)	304,956	86,341	18,382	(386)
Provision for (benefit from) income taxes	(201,310)	108,985	31,754	54,903	—
Net income (loss)	(547,790)	195,971	54,587	(36,521)	(386)
Less: Net income attributable to noncontrolling interest	2,838	2,216	—	—	—
Net income (loss) attributable to Diamondback Energy, Inc.	$(550,628)	$193,755	$54,587	$(36,521)	$(386)
Earnings per common share					
Basic	$(8.74)	$3.67	$1.30		
Diluted	$(8.74)	$3.64	$1.29		
Weighted average common shares outstanding					
Basic	63,019	52,826	42,015		
Diluted	63,019	53,297	42,255		
Pro forma information[3]					
Income (loss) before income taxes, as reported				$18,382	$(386)
Pro forma provision for income taxes				6,553	—
Pro forma net income (loss)				$11,829	$(386)
Pro forma earnings per common share[4]					
Basic				$0.60	
Diluted				$0.60	

	As of December 31,				
(In thousands)	2015	2014	2013	2012[1]	2011[2]
Balance Sheet Data:					
Cash and cash equivalents	20,115	30,183	15,555	26,358	6,959
Net property and equipment	2,597,625	2,791,807	1,446,337	554,242	221,149
Total assets	2,758,412	3,095,481	1,521,614	606,701	263,578
Current liabilities	141,421	266,729	121,320	79,232	42,298
Long-term debt	495,500	673,500	460,000	193	85,000

Total Stockholders'/ Members' equity(5)	1,875,972	1,751,011	845,541	462,068	129,037
Total equity	2,108,973	1,985,213	—	—	—

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	Year Ended December 31,				
(In thousands)	2015	2014	2013	2012[(1)]	2011[(2)]
Other Financial Data:					
Net cash provided by operating activities	$416,501	$356,389	$155,777	$49,692	$30,998
Net cash used in investing activities	(895,050)	(1,481,997)	(940,140)	(183,078)	(81,108)
Net cash provided by financing activities	468,481	1,140,236	773,560	152,785	52,950

	Year Ended December 31,				
(In thousands)	2015	2014	2013	2012[(1)]	2011[(2)]
Adjusted EBITDA[(6)]	$449,245	$398,334	$157,604	$42,783	$31,721

(1) The year ended December 31, 2012 reflects (a) the combined historical financial data of Windsor Permian LLC and Windsor UT LLC, which we sometimes refer to as the Predecessors, due to the transfer of a business between entities under common control and (b) the results of operations attributable to the acquisition of properties from Gulfport Energy Corporation beginning October 11, 2012, the closing date of the property acquisition.

(2) The year ended December 31, 2011 reflects the combined historical financial data of Windsor Permian LLC and Windsor UT LLC due to the transfer of a business between entities under common control.

(3) Diamondback was formed as a holding company on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity. Diamondback is a subchapter C corporation under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision for 2012 as if the Company and the Predecessors were subject to income taxes since December 31, 2011. For 2011 comparative purposes, we have included pro forma financial data to give effect to income taxes assuming the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception. If the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception, we would have incurred net operating losses for income tax purposes in each period. We would have been in a net deferred tax asset position as a result of such tax losses and would have recorded a valuation allowance to reduce each period's deferred tax asset balance to zero. A valuation allowance to reduce each period's deferred tax asset would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respected benefits for income taxes, with the resulting tax expenses for 2011 of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(4) The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the merger of Diamondback Energy LLC into Diamondback were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur.

(5) For the years ended December 31, 2015 and 2014, total stockholders' equity excludes $233.0 million and $234.2 million, respectively, of noncontrolling interest related to Viper Energy Partners LP. There was no equity related to noncontrolling interest for the years ended December 31, 2013, 2012 and 2011.

(6) Adjusted EBITDA is a supplemental non-GAAP financial measure. For our definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) see "–Non-GAAP financial measure and reconciliation" below.

Non-GAAP financial measure and reconciliation

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) plus change in the fair value of open non-hedge derivative instruments, net, interest expense, depreciation, depletion and amortization expense, impairment of oil and natural gas properties, non-cash equity-based compensation expense, capitalized equity-based compensation expense, asset retirement obligation accretion expense, income tax provision (benefit) and non-controlling interest. Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We add the items listed above to net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies or to such measure in our revolving credit facility or any of our other contracts.

The following presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measure of net income (loss).

	Year Ended December 31,				
(In thousands)	2015	2014	2013	2012	2011
Net income (loss):	$(547,790)	$195,971	$54,587	$(36,521)	$(386)
Change in the fair value of open non-hedge derivative instruments, net	112,918	(117,109)	(5,346)	(8,057)	12,972
Interest expense (income)	41,510	34,515	8,059	3,610	2,528
Depreciation, depletion and amortization expense	217,697	170,005	66,597	26,273	16,104
Impairment of oil and natural gas properties	814,798	—	—	—	—
Non-cash equity-based compensation expense	24,572	14,253	2,724	3,482	544
Capitalized equity-based compensation expense	(6,043)	(4,437)	(972)	(1,005)	(106)
Asset retirement obligation accretion expense	833	467	201	98	65
Income tax provision (benefit)	(201,310)	108,985	31,754	54,903	—
Non-controlling interest	(7,940)	(4,316)	—	—	—
Adjusted EBITDA	$449,245	$398,334	$157,604	$42,783	$31,721

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10–K. 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 Item 1A. "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations which we refer to as the Wolfberry play. We intend to 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. Our production was approximately 75% oil, 14% natural gas liquids and 11% natural gas for the year ended December 31, 2015, approximately 76% oil, 14% natural gas liquids and 10% natural gas for the year ended December 31, 2014 and approximately 76% oil, 13% natural gas liquids and 11% natural gas for the year ended December 31, 2013. On December 31, 2015, our net acreage position in the Permian Basin was approximately 84,683 net acres.

2015 Transactions and Recent Developments

Common stock transactions

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

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

In August 2015, we completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $68.74 per share and we received proceeds of approximately $197.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

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

Leasehold and Mineral Interest Transactions

Since January 1, 2015, we have acquired from unrelated third party sellers an aggregate of approximately 16,940 gross (12,672 net) acres in the Midland Basin, primarily in northwest Howard County, for an aggregate purchase price of approximately $437.5 million, subject to certain adjustments. Approximately 83% of this acreage is held by production. We believe the acreage is prospective for horizontal drilling in the Lower Spraberry, Wolfcamp A and Wolfcamp B horizons, and have identified an aggregate of approximately 232 net potential horizontal drilling locations in these horizons based on 660 foot spacing between wells. We currently estimate that approximately 42% of the potential horizontal locations will have approximately 10,000 foot laterals, which can provide higher rates of return and capital efficiency than shorter laterals. The average lateral length for these potential horizontal locations is estimated to be approximately 8,357 feet. We also believe that additional development potential may exist in the Middle Spraberry horizon. Salt water disposal infrastructure is already in place on the acreage in Northwest Howard County, and the acquisitions included 3-D seismic data that can be used to geosteer the drilling of horizontal wells. On

July 9, 2015, we completed the sale of an approximate average 1.5% overriding royalty interest in certain of its acreage primarily located in Howard County, Texas to the Partnership for $31.1 million.

Operational Update

In January 2016, we completed our first three well pad in Glasscock County targeting the Lower Spraberry, Wolfcamp A and Wolfcamp B with an average lateral length of 7,400 feet. The wells are in various stages of flowback and artificial lift but produced in excess of 3,600 BOE/d (81% oil) on a combined basis over seven days. Our second pad in Glasscock County, with two wells targeting the Wolfcamp A and Wolfcamp B, was still cleaning up as of February 15, 2016.

We have drilled our first three-well pad in Howard County targeting the Lower Spraberry, Wolfcamp A and Wolfcamp B. One of the wells on this pad has a 9,600 foot lateral that was drilled in less than 12 days from spud to total depth. As of February 15, 2106, we were drilling our second three-well pad in Howard County. We intend to begin completion of these wells in mid-2016.

We intend to release one of our three horizontal drilling rigs in March 2016. We will continue monitoring the commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans in response to market conditions.

2016 Capital Budget

We expect a 2016 total capital spend of $250.0 million to $375.0 million, consisting of $210.0 million to $315.0 million for horizontal drilling and completions, $25.0 million to $35.0 million for infrastructure and $15.0 million to $25.0 million for non-operated activity and other expenditures. We expect to drill and complete 30 to 70 gross horizontal wells in 2016.

We intend to release one of our three horizontal drilling rigs in March 2016. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans as conditions warrant. We are prepared to decelerate our drilling program if commodity prices deteriorate and accelerate our drilling program if commodity prices improve. If necessary, we can release a second rig in the second quarter of 2016 and continue to operate one rig to hold acreage.

Basis of Presentation

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. The Windsor UT LLC contribution was accounted for as a transaction between entities under common control. Accordingly, the financial information and production data contained in this report have been retrospectively adjusted to include the historical results of Windsor UT LLC at historical carrying values and its operations prior to October 11, 2012, the effective date of the Windsor UT LLC contribution.

Operating Results Overview

During the year ended December 31, 2015, our average daily production was approximately 33,098 BOE/d, consisting of 24,880 Bbls/d of oil, 21,729 Mcf/d of natural gas and 4,596 Bbls/d of natural gas liquids, an increase of 13,624 BOE/d, or 70%, from average daily production of 19,474 BOE/d for the year ended December 31, 2014, consisting of 14,744 Bbls/d of oil, 11,907 Mcf/d of natural gas and 2,745 Bbls/d of natural gas liquids.

During the year ended December 31, 2015, we drilled 64 gross (54.4 net) horizontal wells and four gross (three net) vertical wells and participated in the drilling of 15 gross (six net) non-operated wells in the Permian Basin.

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Reserves and pricing

Ryder Scott prepared estimates of our proved reserves at December 31, 2015, 2014 and 2013 (which include estimated proved reserves attributable to Viper). The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

	2015	2014	2013
Estimated Net Proved Reserves:			
Oil (Bbls)	105,978,711	75,689,589	42,600,852
Natural gas (Mcf)	149,502,744	111,605,260	61,679,496
Natural gas liquids (Bbls)	26,004,144	18,541,932	10,705,724
Total (BOE)	156,899,979	112,832,398	63,586,492

	2015	2014	2013
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$45.07	$87.15	$92.59
Natural gas (per Mcf)	$1.83	$4.85	$4.13
Natural gas liquids (per Bbl)	$12.56	$30.09	$37.82

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the year ended December 31, 2015, our revenues were derived 91% from oil sales, 5% from natural gas liquids sales and 4% from natural gas sales. For the year ended December 31, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% from natural gas sales. For the year ended December 31, 2013, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2015, West Texas Intermediate posted prices ranged from $34.55 to $61.36 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.63 to $3.32 per MMBtu. On December 31, 2015, the West Texas Intermediate posted price for crude oil was $37.13 per Bbl and the Henry Hub spot market price of natural gas was $2.28 per MMBtu.

Over the past several months, oil prices have declined from over $61.00 per Bbl in June 2015 to below $27.00 per Bbl in January 2016 due in large part to increasing supplies and weakening demand growth. Lower 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 determined at the discretion of our lenders.

Principal components of our cost structure

Lease operating and natural gas transportation and treating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

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

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General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other fees for professional services and legal compliance.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

Impairment expense. This is the cost to reduce proved oil and gas properties to the calculated full cost ceiling value.

Other income (expense)

Interest income. This represents the interest received on our cash and cash equivalents.

Interest expense. We have financed a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our revolving credit facility and our net proceeds from the issuance of the senior notes. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Gain/Loss on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of crude oil. This amount represents (i) the recognition of the change in the fair value of open non-hedge derivative contracts as commodity prices change and commodity derivative contracts expire or new ones are entered into, and (ii) our gains and losses on the settlement of these commodity derivative instruments.

Loss from equity investment. This line item represents our proportionate share of the earnings and losses from our investment in the membership interests of Muskie, an equity method investment.

We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

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Results of Operations

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

	Year Ended December 31,		
	2015	2014	2013
	(in thousands, except Bbl, Mcf and BOE amounts)		
Revenues			
Oil, natural gas liquids and natural gas	$446,733	$495,718	$208,002
Operating Expenses			
Lease operating expense	82,625	55,384	21,157
Production and ad valorem taxes	32,990	32,638	12,899
Gathering and transportation expense	6,091	3,288	918
Depreciation, depletion and amortization	217,697	170,005	66,597
Impairment of oil and natural gas properties	814,798	—	—
General and administrative	31,968	21,266	11,036
Asset retirement obligation accretion expense	833	467	201
Total expenses	1,187,002	283,048	112,808
Income (loss) from operations	(740,269)	212,670	95,194
Net interest expense	(41,510)	(34,514)	(8,058)
Other income	728	677	1,077
Other expense	—	(1,416)	—
Gain (loss) on derivative instruments, net	31,951	127,539	(1,872)
Total other income (expense), net	(8,831)	92,286	(8,853)
Income (loss) before income taxes	(749,100)	304,956	86,341
Income tax provision (benefit)	(201,310)	108,985	31,754
Net income (loss)	(547,790)	195,971	54,587
Less: Net income attributable to noncontrolling interest	2,838	2,216	—
Net income (loss) attributable to Diamondback Energy, Inc.	$(550,628)	$193,755	$54,587

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	Year Ended December 31,		
	2015	2014	2013
	(in thousands, except Bbl, Mcf and BOE amounts)		
Production Data:			
Oil (Bbls)	9,081,135	5,381,576	2,022,749
Natural gas (Mcf)	7,931,237	4,345,916	1,730,497
Natural gas liquids (Bbls)	1,677,623	1,001,991	361,079
Combined volumes (BOE)	12,080,631	7,107,886	2,672,244
Daily combined volumes (BOE/d)	33,098	19,474	7,321
Average Prices:			
Oil (per Bbl)	$44.68	$83.48	$93.32
Natural gas (per Mcf)	2.47	4.15	3.61
Natural gas liquids (per Bbl)	12.77	28.39	36.00
Combined (per BOE)	36.98	69.74	77.84
Oil, hedged($ per Bbl)(1)	60.63	85.42	89.75
Average price, hedged($ per BOE)(1)	48.97	71.21	75.14
Average Costs per BOE:			
Lease operating expense	$6.84	$7.79	$7.92
Production and ad valorem taxes	2.73	4.59	4.83
Gathering and transportation expense	0.50	0.46	0.34
General and administrative - cash component	1.11	1.61	3.47
Total operating expense - cash	11.18	14.45	16.56
General and administrative - non-cash component	1.54	1.38	0.66
Depreciation, depletion, and amortization	18.02	23.92	24.92
Interest expense	3.44	4.86	3.02
Total expenses	23.00	30.16	28.60

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

Comparison of the Years Ended December 31, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues decreased by approximately $49.0 million, or 10%, to $446.7 million for the year ended December 31, 2015 from $495.7 million for the year ended December 31, 2014. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 13,624 BOE/d to 33,098 BOE/d during the year ended December 31, 2015 from 19,474 BOE/d during the year ended December 31, 2014. The total decrease in revenue of approximately $49.0 million is largely attributable to lower average sales prices partially offset by higher oil, natural gas liquids and natural gas production volumes for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 3,699,559 Bbls of oil, 675,632 Bbls of natural gas liquids and 3,585,321 Mcf of natural gas for the year ended December 31, 2015 as compared to the year ended December 31, 2014.

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The net dollar effect of the decreases in prices of approximately $391.9 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $342.9 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(38.80)	9,081,135	$(352,356)
Natural gas liquids	$(15.62)	1,677,623	$(26,204)
Natural gas	$(1.68)	7,931,237	$(13,324)
Total revenues due to change in price			$(391,884)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	3,699,559	$83.48	$308,839
Natural gas liquids	675,632	$28.39	$19,181
Natural gas	3,585,321	$4.15	$14,879
Total revenues due to change in production volumes			$342,899
Total change in revenues			$(48,985)

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

Lease Operating Expense. Lease operating expense was $82.6 million ($6.84 per BOE) for the year ended December 31, 2015, an increase of $27.2 million, or 49%, from $55.4 million ($7.79 per BOE) for the year ended December 31, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 169 additional producing wells for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $33.0 million for the year ended December 31, 2015 from $32.6 million for the year ended December 31, 2014. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During the year ended December 31, 2015, our production taxes per BOE decreased by $1.86 as compared to the year ended December 31, 2014, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2015, offset by an increased production as a result of our acquisitions and drilling.

Depreciation, Depletion and Amortization Expense. Depreciation, depletion and amortization expense increased $47.7 million, or 28%, from $170.0 million for the year ended December 31, 2014 to $217.7 million for the year ended December 31, 2015.

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

	Year Ended December 31,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$216,056	$168,674
Depreciation of other property and equipment	1,641	1,331
Depreciation, depletion and amortization expense	$217,697	$170,005
Oil and natural gas properties depreciation, depletion and amortization expense per BOE	$17.84	$23.79
Total depreciation, depletion and amortization expense per BOE	$18.02	$23.92

The increases in depletion of proved oil and natural gas properties of $47.4 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014 resulted primarily from higher total production levels and an increase in net book value on new reserves. On a per BOE basis, depreciation, depletion and amortization decreased primarily due to the impairment of oil and gas properties recorded in 2015.

Impairment of Oil and Natural Gas Properties. During the year ended December 31, 2015, we recorded an impairment of oil and natural gas properties of $814.8 million as a result of the significant decline in prices in 2015. No impairment was recorded in 2014.

General and Administrative Expense. General and administrative expense increased $10.7 million from $21.3 million for the year ended December 31, 2014 to $32.0 million for the year ended December 31, 2015. The increase was due to increases in salaries and benefits expense as a result of an increase in workforce and equity-based compensation.

Net Interest Expense. Net interest expense for the year ended December 31, 2015 was $41.5 million as compared to $34.5 million for the year ended December 31, 2014, an increase of $7.0 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during 2015.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the years ended December 31, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $144.9 million and $10.4 million, respectively. For the year ended December 31, 2015, we had a negative change in the fair value of open derivative instruments of $112.9 million as compared to a positive change in the fair value of open derivative instruments of $117.1 million during the year ended December 31, 2014.

Income Tax Benefit (Expense). We recorded an income tax benefit of $201.3 million for the year ended December 31, 2015 as compared to an income tax expense of $109.0 million for the year ended December 31, 2014. Our effective tax rate was 26.9% for the year ended December 31, 2015 as compared to 35.7% for the year ended December 31, 2014.

Comparison of the Years Ended December 31, 2014 and 2013

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $287.7 million, or 138%, to $495.7 million for the year ended December 31, 2014 from $208.0 million for the year ended December 31, 2013. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 12,153 BOE/d to 19,474 BOE/d during the year ended December 31, 2014 from 7,321 BOE/d during the year ended December 31, 2013. The total increase in revenue of approximately $287.7 million was largely attributable to higher oil, natural gas liquids and natural gas production volumes for the year ended December 31, 2014 as compared to the year ended December 31, 2013, partially offset by lower average sales prices. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 3,358,827 Bbls of oil, 640,912 Bbls of natural gas liquids and 2,615,419 Mcf of natural gas for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

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The net dollar effect of the decreases in prices of approximately $58.2 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $346.0 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(9.84)	5,381,576	$(52,959)
Natural gas liquids	$(7.61)	1,001,991	$(7,625)
Natural gas	$0.54	4,345,916	$2,345
Total revenues due to change in price			$(58,239)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	3,358,827	$93.32	$313,444
Natural gas liquids	640,912	$36.00	$23,071
Natural gas	2,615,419	$3.61	$9,440
Total revenues due to change in production volumes			$345,955
Total change in revenues			$287,716

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

Lease Operating Expense. Lease operating expense was $55.4 million ($7.79 per BOE) for the year ended December 31, 2014, an increase of $34.2 million, or 162%, from $21.2 million ($7.92 per BOE) for the year ended December 31, 2013. The increase was due to increased drilling activity and acquisitions, which resulted in 389 additional producing wells for the year ended December 31, 2014 as compared to the year ended December 31, 2013. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells. On a per BOE basis, lease operating expense remained stable as new volumes came on line and expenses were held in line or were reduced.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $32.6 million for the year ended December 31, 2014 from $12.9 million for the year ended December 31, 2013. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During the year ended December 31, 2014, our production taxes per BOE decreased by $0.24 as compared to the year ended December 31, 2013, primarily reflecting the impact of lower oil and natural gas prices on production taxes. Our ad valorem taxes have increased primarily as a result of increased valuations on our properties.

Depreciation, Depletion and Amortization Expense. Depreciation, depletion and amortization expense increased $103.4 million, or 155%, from $66.6 million for the year ended December 31, 2013 to $170.0 million for the year ended December 31, 2014.

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

	Year Ended December 31, 2014	2013
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$168,674	$65,821
Depreciation of other property and equipment	1,331	776
Depreciation, depletion and amortization expense	$170,005	$66,597
Oil and natural gas properties depreciation, depletion and amortization expense per BOE	$23.79	$24.63
Total depreciation, depletion and amortization expense per BOE	$23.92	$24.92

The increases in depletion of proved oil and natural gas properties of $102.9 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013 resulted primarily from higher total production levels, increased net book value on new reserves added and an increase in capitalized interest to the full cost pool. On a per BOE basis, depreciation, depletion and amortization expense decreased primarily due to the increased net book value on new reserves and acquisitions.

General and Administrative Expense. General and administrative expense increased $10.2 million from $11.0 million for the year ended December 31, 2013 to $21.3 million for the year ended December 31, 2014. The increase was due to increases in equity-based compensation, salary, legal, professional service and advisory service expenses. These increases were partially offset by increases in general and administrative costs related to exploration and development activity capitalized to the full cost pool and increases in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the year ended December 31, 2014 was $34.5 million as compared to $8.1 million for the year ended December 31, 2013, an increase of $26.5 million. This increase was due primarily to the issuance of $450.0 million in aggregate principal amount of our 7.625% senior notes in September 2013.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the years ended December 31, 2014 and 2013, we had a cash gain on settlement of derivative instruments of $10.4 million and a cash loss on settlement of derivative instruments of $7.2 million, respectively. For the years ended December 31, 2014 and 2013, we had a positive change in the fair value of open derivative instruments of $117.1 million and $5.3 million, respectively.

Income Tax Expense. We recorded income tax expense of $109.0 million for the year ended December 31, 2014 as compared to $31.8 million for the year ended December 31, 2013. Our effective tax rate was 35.7% for the year ended December 31, 2014 as compared to 36.8% for the year ended December 31, 2013.

Liquidity and Capital Resources

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

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Liquidity and Cash Flow

Our cash flows for the years ended December 31, 2015, 2014 and 2013 are presented below:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Net cash provided by operating activities	$416,501	$356,389	$155,777
Net cash used in investing activities	(895,050)	(1,481,997)	(940,140)
Net cash provided by financing activities	$468,481	$1,140,236	$773,560
Net change in cash	$(10,068)	$14,628	$(10,803)

Operating Activities

Net cash provided by operating activities was $416.5 million for the year ended December 31, 2015 as compared to $356.4 million for the year ended December 31, 2014. The increase in operating cash flows is primarily the result of the increase in our oil and natural gas revenues due to a 70.0% increase in our net BOE production partially offset by a 47.0% decrease in our net realized sales prices.

Net cash provided by operating activities was $356.4 million for the year ended December 31, 2014 as compared to $155.8 million for the year ended December 31, 2013. The increase in operating cash flows is primarily a result of the increase in our oil and natural gas revenues due to a 166.0% increase in our net BOE production partially offset by a 10.4% decrease in our net realized sales prices.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. See "–Sources of our revenue" and Item 1A. "Risk Factors" above.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $895.1 million, $1,482.0 million and $940.1 million during the years ended December 31, 2015, 2014 and 2013 respectively.

During the year ended December 31, 2015, we spent $419.5 million on capital expenditures in conjunction with our drilling program, in which we drilled 64 gross (54 net) horizontal wells and four gross (three net) vertical wells and participated in the drilling of 15 gross (six net) non-operated wells, $437.5 million on leasehold acquisitions, $43.9 million on royalty interest acquisitions and $1.2 million for the purchase of other property and equipment.

During the year ended December 31, 2014, we spent $499.8 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 82 gross (67 net) horizontal wells and 27 gross (22 net) vertical wells and participated in the drilling of four gross (two net) non-operated wells. We spent an additional $845.8 million on leasehold costs, $44.2 million for the purchase of other property and equipment, $57.7 million on the acquisitions of mineral interests underlying approximately 10,364 gross (3,261 net) acres in the Midland and Delaware basins and approximately $33.9 million for a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests.

During the year ended December 31, 2013, we spent $297.7 million on capital expenditures in conjunction with our drilling program in which drilled 77 gross (70 net) wells and participated in the drilling of four gross (two net) non-operated wells. We spent an additional $444.1 million on the acquisition of mineral interests, $177.3 million on leasehold costs, $2.2 million for the purchase of other property and equipment and $0.3 million, net, on the settlement of non-hedge derivative instruments and $18.6 million for the post-closing adjustment associated with our acquisition of Gulfport Energy Corporation's oil and natural gas assets in the Permian Basin in connection with our initial public offering in October 2012.

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Our investing activities for the years ended December 31, 2015, 2014 and 2013 are summarized in the following table:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Drilling, completion and infrastructure	$(419,512)	$(499,848)	$(297,713)
Acquisition of leasehold interests	(437,455)	(845,826)	(177,343)
Acquisition of Gulfport properties	—	—	(18,550)
Acquisition of royalty interests	(43,907)	(57,689)	(444,083)
Purchase of other property and equipment	(1,213)	(44,213)	(2,234)
Proceeds from sale of assets	9,739	56	72
Equity investments	(2,702)	(34,477)	—
Settlement of non-hedge derivative instruments	—	—	(289)
Net cash used in investing activities	$(895,050)	$(1,481,997)	$(940,140)

Financing Activities

Net cash provided by financing activities for the years ended December 31, 2015, 2014 and 2013 was $468.5 million, $1,140.2 million and $773.6 million, respectively. The 2015 amount provided by financing activities was primarily attributable to the aggregate proceeds from our January, May and August 2015 equity offerings of $650.7 million partially offset by repayments of net borrowings of $184.5 million, under our credit facility. During the year ended December 31, 2014, the amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering, net proceeds of $137.2 million from the Viper Offering, net proceeds of $485.0 million from our July 2014 equity offering, net proceeds of $94.8 million from the Viper September 2014 equity offering and borrowings, net of repayment, of $213.5 million under our credit facility. For the year ended December 31, 2013, the amount provided by financing activities was primarily attributable to (a) the net proceeds of $144.4 million from our May 2013 equity offering, $177.5 million from our August 2013 equity offering, $450.0 million from our September 2013 senior note offering and (b) net borrowings of $10.0 million under our revolving credit facility. In both 2014 and 2013, these proceeds were used primarily to acquire property and fund our drilling costs.

Senior Notes

On September 18, 2013, we completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021, which we refer to as the senior notes. The senior notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year and will mature on October 1, 2021. On June 23, 2014, in connection with the Viper Offering, we designated Viper, the general partner and Viper Energy Partners LLC, as unrestricted subsidiaries and, upon such designation, Viper Energy LLC, which was a guarantor under the indenture governing of the senior notes, was released as a guarantor under the indenture. As of December 31, 2015, the senior notes were fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any of our future restricted subsidiaries. The net proceeds from the senior notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin.

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

We have the option to redeem the senior notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest

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to, but not including, the date of redemption. In addition, prior to October 1, 2016, we may redeem all or a part of the senior notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium at the redemption date. Furthermore, before October 1, 2016, we may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the senior notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the senior notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

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

Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014 and November 13, 2014, with a syndicate of banks, including Wells Fargo, as administrative agent, sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $2.0 billion, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2015, the borrowing base was set at $750.0 million, although we elected a commitment amount of $500.0 million. As of December 31, 2015, we had outstanding borrowings of $11.0 million, which bore a weighted-average interest rate of 1.92%, and $489.0 million available for future borrowings under this facility.

The June 9, 2014 amendment modified certain provisions of the credit agreement to, among other things, allow us to designate one or more of our subsidiaries as "Unrestricted Subsidiaries" that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, we designated Viper, the general partner and Viper Energy Partners LLC as unrestricted subsidiaries under the credit agreement. As of December 31, 2015, the loan was guaranteed by us, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any of our future restricted subsidiaries. The credit agreement is also secured by substantially all of our assets and the assets of Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent that the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750.0 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may

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require a portion of the outstanding principal of the loan to be repaid. As of December 31, 2015, we had $450.0 million of senior notes outstanding.

As of December 31, 2015, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Viper’s Facility-Wells Fargo Bank

On July 8, 2014, Viper entered into a secured revolving credit agreement with Wells Fargo Bank, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on Viper’s oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, Viper may request up to three additional redeterminations of the borrowing base during any 12-month period. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. On November 13, 2015, the borrowing base was increased from $175.0 million to $200.0 million. As of December 31, 2015, the borrowing base was set at $200.0 million. Viper had $34.5 million outstanding under its credit agreement.

The outstanding borrowings under Viper’s credit agreement bear interest at a rate elected by Viper that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Viper is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent that the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of the assets of Viper and its subsidiaries.

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

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

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

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

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Capital Requirements and Sources of Liquidity

Our board of directors approved a 2016 capital budget for drilling and infrastructure of $250.0 million to $375.0 million, representing a decrease of 26% over our 2015 capital budget. We estimate that, of these expenditures, approximately:

- $210.0 million to $315.0 million will be spent on drilling and completing 30 to 70 gross (25 to 58 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;
- $25.0 million to $35.0 million will be spent on infrastructure; and
- $15.0 million to $25.0 million will be spent on non-operated activity and other expenditures.

During the year ended December 31, 2015, our aggregate capital expenditures for drilling and infrastructure were $419.5 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the year ended December 31, 2015, we spent approximately $437.5 million on acquisitions of leasehold interests.

The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. We currently intend to release one of our three horizontal drilling rigs in March 2016 and we have the option to release a second rig in the second quarter of 2016.

Based upon current oil and natural gas price and production expectations for 2016, we believe that our cash flow from operations and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2016. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. Further, our 2016 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

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

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Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2015:

	Payments Due by Period				
	2016	2017-2018	2019-2020	Thereafter	Total
	(in thousands)				
Secured revolving credit facility[1]	$—	$11,000	$—	$—	$11,000
Interest expense related to the secured revolving credit facility	2,813	4,454	—	—	$7,267
Senior notes	—	—	—	450,000	$450,000
Interest expense the senior notes[2]	34,313	68,626	68,626	34,313	$205,878
Viper's secured revolving credit facility[1]	—	—	—	34,500	$34,500
Interest and commitment fees under Viper's credit agreement[3]	2,636	750	1,500	386	$5,272
Asset retirement obligations [4]	193	—	—	12,518	$12,711
Drilling commitments[5]	29,536	36,759	589	—	$66,884
Operating lease obligations	1,935	4,026	3,498	9,583	$19,042
	$71,426	$125,615	$74,213	$541,300	$812,554

(1) Includes the outstanding principal amount under the revolving credit facilities, the table does not include interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged.

(2) Interest represents the scheduled cash payments on the senior notes.

(3) Includes only the minimum amount of interest and commitment fees due which, as of December 31, 2015, includes a commitment fee equal to 0.375% per year of the unused portion of the borrowing base of Viper’s credit agreement.

(4) Amounts represent our estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 6 of the notes to our consolidated financial statements set forth in Part IV, Item 15 of this Form 10-K.

(5) Drilling commitments represent future minimum expenditure commitments for drilling rig services under contracts to which the Company was a party on December 31, 2015.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 2 of the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Use of Estimates

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated by our 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 we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our 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 gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, equity-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

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Method of accounting for oil and natural gas properties

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Revenue recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. We account for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when our volumes exceed our estimated remaining recoverable reserves. No receivables are recorded for those wells where we have taken less than our ownership share of production. We did not have any gas imbalances as of December 31, 2015, 2014 and 2013. Revenues from oil and natural gas services are recognized as services are provided.

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Impairment

We use the full cost method of accounting for our oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. The inclusion of our unevaluated costs into the amortization base is expected to be completed within three to five years. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, we are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions 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.

Asset retirement obligations

We measure the future cost to retire our tangible long-lived assets and recognize such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

Our asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. We estimate 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 gas property balance.

Derivatives

From time to time, we have used energy derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil. We recognize all of our derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further on the type of hedging relationship. None of our derivatives were designated as hedging instruments during the years ended December 31, 2015, 2014 and 2013. For derivative instruments not designated as hedging instruments, changes in the fair value of these instruments are recognized in earnings during the period of change.

Accounting for Equity-Based Compensation

We grant various types of equity-based awards including stock options and restricted stock units. These plans and related accounting policies are defined and described more fully in Note 10–Equity-Based Compensation. Stock compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

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Income Taxes

We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. We are currently evaluating the impact, if any, that the adoption of this update will have on our financial position, results of operations and liquidity.

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, "Interest–Imputation of Interest". This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued. Adoption of the new guidance will only affect the presentation of our consolidated balance sheets and will not have a material impact on our consolidated financial statements.

In July 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-11, "Inventory". This update applies to all inventory that is not measured using last-in, first-out or the retail inventory method. Under this update, an entity should measure inventory at the lower of cost and net realizable value. This standard will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. This standard should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. We are currently evaluating the impact that the adoption of this update will have on our financial position, results of operations and liquidity.

In November 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-17, "Income Taxes". This update requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The standard will be effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early application will be permitted as of the beginning of an interim or annual reporting period. This standard may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. Adoption of the new guidance will only affect the presentation of our consolidated balance sheets and will not have a material impact on our consolidated financial statements.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on results of operations for the years ended December 31, 2015, 2014 and 2013. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

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Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2015. Please read Note 15 included in Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

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

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

At December 31, 2015, we had a net asset derivative position of $4.6 million, related to our price swap derivatives, as compared to a net asset derivative position of $117.5 million as of December 31, 2014 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of December 31, 2015, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to $4.3 million, a decrease of $0.3 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $5.0 million, an increase of $0.3 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 $41.3 million at December 31, 2015) and receivables from the sale of our oil and natural gas production (approximately $37.6 million at December 31, 2015).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (59%); and Enterprise Crude Oil LLC (15%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%); and Enterprise Crude Oil LLC (16%). For the year ended December 31, 2013, two purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At December 31, 2015, we had five customers that represented approximately 73% of our total joint operations receivables. At December 31, 2014, we had two customer that represented approximately 61% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding

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in relation to the borrowing base. Our weighted-average interest rate on borrowings under our credit facility was 1.92% at December 31, 2015. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.1 million based on the $11.0 million outstanding in the aggregate under our revolving credit facility on December 31, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 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 December 31, 2015, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2015, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the year ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in the Company's internal control over financial reporting and determined that the Company maintained effective internal control over financial reporting as of December 31, 2015.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2015. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2015, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Diamondback Energy, Inc.

We have audited the internal control over financial reporting of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2015, and our report dated February 19, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 19, 2016

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2015.

We have adopted a Code of Business Conduct and Ethics that applies to our Chief Executive Officer, Chief Financial Officer, principal accounting officer and controller and persons performing similar functions. Any amendments to or waivers from the code of business conduct and ethics will be disclosed on our website. The Company also has made the Code of Business Conduct and Ethics available on our website under the “Corporate Governance” section at http://ir.diamondbackenergy.com. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2015.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2015.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2015.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2015.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. Financial Statements

Report of Independent Registered Public Accounting Firm	F-1
Consolidated Balance Sheets	F-2
Consolidated Statements of Operations	F-3
Consolidated Statement of Stockholders' Equity	F-4
Consolidated Statements of Cash Flows	F-5
Notes to Consolidated Financial Statements	F-7

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company’s consolidated financial statements and related notes.

3. Exhibits

The Exhibit Index beginning on page E–1 of this report is incorporated herein by reference.

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SIGNATURES

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

DIAMONDBACK ENERGY, INC.

Date: February 19, 2016

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

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Steven E. West Steven E. West	Chairman of the Board and Director	February 19, 2016
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2016
/s/ Michael P. Cross Michael P. Cross	Director	February 19, 2016
/s/ David L. Houston David L. Houston	Director	February 19, 2016
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 19, 2016
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer, Senior Vice President, and Assistant Secretary (Principal Financial and Accounting Officer)	February 19, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Diamondback Energy, Inc.

We have audited the accompanying consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2015 and 2014, and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Diamondback Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2016 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 19, 2016

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2015	2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$20,115	$30,183
Restricted cash	500	500
Accounts receivable:		
Joint interest and other	41,309	50,943
Oil and natural gas sales	36,004	43,050
Related party	1,591	4,001
Inventories	1,728	2,827
Derivative instruments	4,623	115,607
Prepaid expenses and other	2,875	4,600
Total current assets	108,745	251,711
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($1,106,816 and $773,520 excluded from amortization at December 31, 2015 and December 31, 2014, respectively)	3,955,373	3,118,597
Pipeline and gas gathering assets	7,174	7,174
Other property and equipment	48,621	48,180
Accumulated depletion, depreciation, amortization and impairment	(1,413,543)	(382,144)
Net property and equipment	2,597,625	2,791,807
Derivative instruments	—	1,934
Other assets	52,042	50,029
Total assets	$2,758,412	$3,095,481
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable-trade	$20,008	$26,230
Accounts payable-related party	217	—
Accrued capital expenditures	59,937	129,397
Other accrued liabilities	44,293	41,149
Revenues and royalties payable	16,966	30,000
Deferred income taxes	—	39,953
Total current liabilities	141,421	266,729
Long-term debt	495,500	673,500
Asset retirement obligations	12,518	8,447
Deferred income taxes	—	161,592
Total liabilities	649,439	1,110,268
Commitments and contingencies (Note 15)		
Stockholders’ equity:		
Common stock, $0.01 par value, 100,000,000 shares authorized, 66,797,041 issued and outstanding at December 31, 2015; 56,887,583 issued and outstanding at December 31, 2014	668	569

Additional paid-in capital	2,229,664	1,554,174
Retained earnings	(354,360)	196,268
Total Diamondback Energy, Inc. stockholders' equity	1,875,972	1,751,011
Noncontrolling interest	233,001	234,202
Total equity	2,108,973	1,985,213
Total liabilities and equity	$2,758,412	$3,095,481

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2015	2014	2013
	(In thousands, except per share amounts)		
Revenues:			
Oil sales	$405,715	$449,244	$188,753
Natural gas sales	16,952	8,662	3,715
Natural gas sales - related party	2,640	9,366	2,534
Natural gas liquid sales	18,882	13,408	8,304
Natural gas liquid sales - related party	2,544	15,038	4,696
Total revenues	446,733	495,718	208,002
Costs and expenses:			
Lease operating expenses	82,404	55,166	19,991
Lease operating expenses - related party	221	218	1,166
Production and ad valorem taxes	32,837	31,160	12,399
Production and ad valorem taxes - related party	153	1,478	500
Gathering and transportation	5,122	618	237
Gathering and transportation - related party	969	2,670	681
Depreciation, depletion and amortization	217,697	170,005	66,597
Impairment of oil and natural gas properties	814,798	—	—
General and administrative expenses (including non-cash equity-based compensation, net of capitalized amounts, of $18,529, $9,816 and $1,752 for the year ended December 31, 2015, 2014 and 2013, respectively)	29,640	19,921	9,870
General and administrative expenses - related party	2,328	1,345	1,166
Asset retirement obligation accretion expense	833	467	201
Total costs and expenses	1,187,002	283,048	112,808
Income (loss) from operations	(740,269)	212,670	95,194
Other income (expense)			
Interest income (expense)	(41,510)	(34,514)	(8,058)
Other income	567	556	—
Other income - related party	161	121	1,077
Other expense	—	(1,416)	—
Gain (loss) on derivative instruments, net	31,951	127,539	(1,872)
Total other income (expense), net	(8,831)	92,286	(8,853)
Income (loss) before income taxes	(749,100)	304,956	86,341
Provision for (benefit from) income taxes	(201,310)	108,985	31,754
Net income (loss)	(547,790)	195,971	54,587
Less: Net income attributable to noncontrolling interest	2,838	2,216	—
Net income (loss) attributable to Diamondback Energy, Inc.	$(550,628)	$193,755	$54,587
Earnings per common share			
Basic	$(8.74)	$3.67	$1.30
Diluted	$(8.74)	$3.64	$1.29
Weighted average common shares outstanding			
Basic	63,019	52,826	42,015

Diluted	63,019	53,297	42,255

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional Paid-in Capital	Retained Earnings	Non-Controlling Interest	Total
	Shares	Amount				
	(In thousands)					
Balance December 31, 2012	36,986	$370	$513,772	$(52,074)	$ —	$462,068
Stock-based compensation	—	—	2,724	—	—	2,724
Tax benefits related to stock-based compensation	—	—	749	—	—	749
Common shares issued in public offering, net of offering costs	9,775	98	321,814	—	—	321,912
Exercise of stock options and vesting of restricted stock units	345	3	3,498	—	—	3,501
Net income	—	—	—	54,587	—	54,587
Balance December 31, 2013	47,106	471	842,557	2,513	—	845,541
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	232,198	232,198
Unit-based compensation	—	—	—	—	2,102	2,102
Distribution to noncontrolling interest	—	—	—	—	(2,314)	(2,314)
Stock-based compensation	—	—	12,152	—	—	12,152
Tax benefits related to stock-based compensation	—	—	(749)	—	—	(749)
Common shares issued in public offering, net of offering costs	9,200	92	689,390	—	—	689,482
Exercise of stock options and awards of restricted stock	518	5	7,075	—	—	7,080
Equity payment- Wexford Advisory Services (See Note 11)	64	1	3,749	—	—	3,750
Net income	—	—	—	193,755	2,216	195,971
Balance December 31, 2014	56,888	569	1,554,174	196,268	234,202	1,985,213
Unit-based compensation	—	—	—	—	3,929	3,929
Stock-based compensation	—	—	20,645	—	—	20,645
Distribution to noncontrolling interest	—	—	—	—	(7,968)	(7,968)
Common shares issued in public offering, net of offering costs	9,488	94	649,979	—	—	650,073
Exercise of stock options and awards of restricted stock	421	5	4,866	—	—	4,871
Net income (loss)	—	—	—	(550,628)	2,838	(547,790)
Balance December 31, 2015	66,797	$668	$2,229,664	$(354,360)	$ 233,001	$2,108,973

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$(547,790)	$195,971	$54,587
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for (benefit from) deferred income taxes	(201,545)	108,985	31,563
Excess tax benefit from stock-based compensation	—	—	(749)
Impairment of oil and natural gas properties	814,798	—	—
Asset retirement obligation accretion expense	833	467	201
Depreciation, depletion, and amortization	217,697	170,005	66,597
Amortization of debt issuance costs	2,601	2,125	1,018
Change in fair value of derivative instruments	112,918	(117,109)	(5,346)
Equity-based compensation expense	18,529	9,816	1,752
(Gain) loss on sale of assets, net	668	1,396	(39)
Changes in operating assets and liabilities:			
Accounts receivable	8,998	(39,442)	(19,973)
Accounts receivable-related party	2,149	(2,699)	(532)
Restricted cash	—	(500)	—
Inventories	224	915	554
Prepaid expenses and other	(1,310)	(4,601)	(271)
Accounts payable and accrued liabilities	802	6,829	20,588
Accounts payable and accrued liabilities-related party	218	(17)	(128)
Accrued interest	(255)	3,473	—
Revenues and royalties payable	(13,034)	20,775	5,955
Net cash provided by operating activities	416,501	356,389	155,777
Cash flows from investing activities:			
Additions to oil and natural gas properties	(419,241)	(494,708)	(278,809)
Additions to oil and natural gas properties-related party	(271)	(3,631)	(13,777)
Acquisition of Gulfport properties	—	—	(18,550)
Acquisition of royalty interests	(43,907)	(57,689)	(444,083)
Acquisition of leasehold interests	(437,455)	(845,826)	(177,343)
Pipeline and gas gathering assets	—	(1,509)	(5,127)
Purchase of other property and equipment	(1,213)	(44,213)	(2,234)
Proceeds from sale of assets	9,739	56	72
Equity investments	(2,702)	(34,477)	—
Settlement of non-hedge derivative instruments	—	—	(289)
Net cash used in investing activities	(895,050)	(1,481,997)	(940,140)
Cash flows from financing activities:			
Proceeds from borrowings on credit facility	425,001	509,400	59,000
Repayment on credit facility	(603,001)	(295,900)	(49,000)
Proceeds from senior notes	—	—	450,000
Debt issuance costs	(526)	(3,469)	(12,361)
Public offering costs	(586)	(2,994)	(1,009)
Proceeds from public offerings	650,688	928,432	322,680

Exercise of stock options	4,873	7,081	3,501
Excess tax benefits of stock-based compensation	—	—	749
Distribution to non-controlling interest	(7,968)	(2,314)	—

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

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net cash provided by financing activities	468,481	1,140,236	773,560
Net increase (decrease) in cash and cash equivalents	(10,068)	14,628	(10,803)
Cash and cash equivalents at beginning of period	30,183	15,555	26,358
Cash and cash equivalents at end of period	$20,115	$30,183	$15,555

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$38,758	$31,621	$404
Cash paid for income taxes	$267	$—	$—
Supplemental disclosure of non-cash transactions:			
Asset retirement obligation incurred	$594	$703	$226
Asset retirement obligation revisions in estimated liability	$(69)	$588	$—
Asset retirement obligation acquired	$3,159	$3,726	$471
Change in accrued capital expenditures	$(69,460)	$54,748	$45,252
Capitalized stock-based compensation	$6,043	$4,437	$972

See accompanying notes to 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”) is an independent oil and 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. Diamondback was incorporated in Delaware on December 30, 2011.

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

The wholly-owned subsidiaries of Diamondback, as of December 31, 2015, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, and White Fang Energy LLC, a Delaware limited liability company. The consolidated subsidiaries include the wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership, and Viper Energy Partners LLC, a Delaware limited liability company.

Basis of Presentation

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

The Partnership is consolidated in the financial statements of the Company. As of December 31, 2015, the Company owned approximately 88% of the common units of the Partnership and the Company’s wholly owned subsidiary, Viper Energy Partners GP LLC, is the General Partner of the Partnership.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

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

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

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments.

Restricted Cash

A subsidiary of the Company entered into an agreement to purchase certain overriding royalty interests and deposited $0.5 million in escrow. The agreement provided that the subsidiary would have the right to terminate the agreement and receive a return of the deposit if the subsidiary in good faith asserted title defects in excess of a certain amount. The subsidiary asserted title defects in excess of the amount and requested that the escrow agent return the deposit. The seller provided the escrow agent with notice alleging the subsidiary did not timely assert the defects in good faith. The escrow agent tendered the deposit to the court subject to a judicial determination of the proper payment of the funds.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2015 or December 31, 2014.

Derivative Instruments

The Company is required to recognize its derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. 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 change in fair value on derivative instruments in the consolidated statements of operations.

Fair Value of Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, restricted cash, receivables, payables, derivatives, notes payable and senior notes. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments. The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The note payable is carried at cost, which approximates fair value due to the nature of the instrument and relatively short maturity. The fair value of the senior notes are determined using quoted market prices. Derivatives are recorded at fair value (see Note 14–Fair Value Measurements).

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. 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. Any income from services provided by subsidiaries to working interest owners of properties in which the Company also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties proportionate to the Company's investment in the subsidiary (see Note 7–Equity Method Investments). Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $17.84, $23.79 and $24.63 for the years ended December 31, 2015, 2014 and 2013, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $216.1 million, $168.7 million and $65.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions, 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. During the year ended December 31, 2015, the Company recorded an impairment on proved oil and natural gas properties of $814.8 million. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2014 and 2013, respectively.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Other Property and Equipment

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years. Depreciation expense for other property and equipment was $1.6 million, $1.3 million and $0.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Asset Retirement Obligations

The Company measures the future cost to retire its tangible long-lived assets and recognizes such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

The Company records a liability relating to the retirement and removal of all assets used in their businesses. Asset retirement obligations represent the future abandonment costs of tangible assets, namely wells. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

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

Impairment of Long-Lived Assets

Other property and equipment used in operations are reviewed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its estimated future undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no such impairment losses for the years ended December 31, 2015, 2014 and 2013, respectively.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest cannot exceed gross interest expense. The Company capitalized interest of $5.3 million and $4.0 million amounts for the years ended December 31, 2014 and 2013, respectively. The Company did not have any capitalized interest for the year ended December 31, 2015.

Inventories

Inventories are stated at the lower of cost or market and consist of tubular goods and equipment at December 31, 2015 and 2014. The Company’s tubular goods and equipment are primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations and is carried at lower of cost or market. “Market”, in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. As of December 31, 2015, the Company estimated that all of its tubular goods and equipment will be utilized within one year.

Debt Issuance Costs

Other assets included capitalized costs of $18.2 million and $13.8 million, net of accumulated amortization of $6.5 million and $3.9 million, as of December 31, 2015 and 2014, respectively. The costs associated with the Senior Notes are being amortized over the term of the Senior Notes using the effective interest method. The costs associated with the Company’s credit facility are being amortized over the term of the facility.

Other Accrued Liabilities

Other accrued liabilities consist of the following:

	December 31,	
	2015	2014
	(In thousands)	
Prepaid drilling liability	$12,683	$3,758
Interest payable	8,606	8,861
Lease operating expense payable	14,100	11,851
Taxes payable	518	9,952
Current portion of asset retirement obligations	193	39
Other	8,193	6,688

Total other accrued liabilities	$44,293	$41,149

Revenue and Royalties Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue and royalties payable in the accompanying consolidated balance sheets. The Company recognizes revenue for only its net revenue interest in oil and natural gas properties.

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

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. The Company accounts for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when the Company's overtake volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of production. The Company did not have any gas imbalances as of December 31, 2015 or December 31, 2014. Revenues from oil and natural gas services are recognized as services are provided.

Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, generally the Company's share of investees' earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company would recognize an impairment provision. There was no impairment for the Company's equity investments for the years ended December 31, 2015, 2014 and 2013.

For additional information on the Company's investments, see Note 7–Equity Method Investments.

Accounting for Equity-Based Compensation

The Company grants various types of stock-based awards including stock options and restricted stock units. These plans and related accounting policies are defined and described more fully in Note 10–Equity-Based Compensation. Stock compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (59%); and Enterprise Crude Oil LLC (15%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%); and Enterprise Crude Oil LLC (16%). For the year ended December 31, 2013, two purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Environmental Compliance and Remediation

Environmental compliance and remediation costs, including ongoing maintenance and monitoring, are expensed as incurred. Liabilities are accrued when environmental assessments and remediation are probable, and the costs can be reasonably estimated.

Income Taxes

Diamondback uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to margin tax in the state of Texas. During the years ended December 31, 2015, 2014 and 2013, there was no margin tax expense. The Company’s 2011, 2012, 2013, 2014 and 2015 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2015 and December 31, 2014, the Company had no unrecognized tax benefits that would have a material impact on the effective rate. The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2015, 2014 and 2013, there was no interest or penalties associated with uncertain tax positions recognized in the Company's consolidated financial statements.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is currently evaluating the impact, if any, that the adoption of this update will have on the Company's financial position, results of operations and liquidity.

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, "Interest–Imputation of Interest". This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued. Adoption of the new guidance will only affect the presentation of the Company's consolidated balance sheets and will not have a material impact on its consolidated financial statements.

In July 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-11, "Inventory". This update applies to all inventory that is not measured using last-in, first-out or the retail inventory method. Under this update, an entity should measure inventory at the lower of cost and net realizable value. This standard will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. This standard should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the impact that the adoption of this update will have on the Company's financial position, results of operations and liquidity.

In November 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-17, "Income Taxes". This update requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The standard will be effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early application will be permitted as of the beginning of an interim or annual reporting period. This standard may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. Adoption of the new guidance will only affect the presentation of the Company's consolidated balance sheets and will not have a material impact on its consolidated financial statements.

3. ACQUISITIONS
2015 Activity

Since January 1, 2015, the Company has completed acquisitions from unrelated third party sellers of an aggregate of approximately 16,940 gross (12,672 net) acres in the Midland Basin, primarily in northwest Howard County, for an aggregate purchase price of approximately $437.5 million, subject to certain adjustments. The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded with the net proceeds of the May 2015 equity offering discussed in Note 9–Capital Stock and Earnings Per Share and borrowings under the Company's revolving credit facility discussed in Note 8–Debt.

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

2014 Activity

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

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition date. The aggregate consideration transferred was $523.3 million in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

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

The Company has included in its consolidated statements of operations revenues of $12.3 million and direct operating expenses of $4.6 million for the period from September 9, 2014 to December 31, 2014 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

On August 25, 2014, the Company completed an acquisition of surface rights in the Permian Basin from an unrelated third party seller. The Company acquired surface rights to approximately 4,200 acres for approximately $41.9 million.

On February 27 and 28, 2014, the Company completed acquisitions of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded with the net proceeds of the February 2014 equity offering and borrowings under the Company's revolving credit facility discussed in Note 8–Debt.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition dates. The aggregate consideration transferred was $292.2 million in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

	(in thousands)
Proved oil and natural gas properties	$170,174
Unevaluated oil and natural gas properties	123,243
Total assets acquired	293,417
Asset retirement obligations	1,258

Total liabilities assumed	1,258
Total fair value of net assets	$292,159

The Company has included in its consolidated statements of operations revenues of $40.5 million and direct operating expenses of $7.8 million for the period from February 28, 2014 to December 31, 2014 due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

Diamondback Energy, Inc. and Subsidiaries
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During the year ended December 31, 2014, the Partnership acquired (i) mineral interests underlying an aggregate of approximately 10,364 gross (3,261 net) acres in the Midland and Delaware basins for approximately $57.7 million and (ii) a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests for approximately $33.9 million. The equity interest is so minor that we have no influence over partnership operating and financial policies and is accounted for under the cost method.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the years ended December 31, 2014 and 2013 have been prepared to give effect to the February 27 and 28, 2014 acquisitions and the September 9, 2014 acquisition as if they had occurred on January 1, 2013. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2013. The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Pro Forma (Unaudited) Year Ended December 31,	
	2014	2013
	(in thousands)	
Revenues	$541,103	$315,736
Income from operations	224,382	146,429
Net income	201,257	86,277

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

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. As part of the closing of the acquisition, the mineral interests were conveyed from the previous owners to Viper Energy Partners LLC and, subsequently, were contributed to the Partnership on June 17, 2014. See Note 4 – Viper Energy Partners LP for additional information regarding the Partnership. The mineral interests entitle the holder of such interests to receive a 21.4% royalty interest on all production on an acreage weighted basis from this acreage with no additional future capital or operating expense required. The $440.0 million purchase price was funded with the net proceeds of the Company's offering of Senior Notes discussed in Note 8–Debt.

4. VIPER ENERGY PARTNERS LP

The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by Diamondback on February 27, 2014, to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of December 31, 2015, the Company owned approximately 88% of the common units of the Partnership.

Prior to the completion on June 23, 2014 of the Viper Offering, Diamondback owned all of the general and limited partner interests in the Partnership. The Viper Offering consisted of 5,750,000 common units representing approximately 8%

of the limited partner interests in the Partnership at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. The Partnership received proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the Viper Offering, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. In addition, in connection with the closing of the Viper Offering, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the Viper Offering. As of December 31, 2014, the Partnership had distributed $148.8 million to Diamondback and the Partnership recorded a payable balance of approximately $11.3 million. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. During the year ended December 31, 2015, the Partnership distributed $60.6 million to Diamondback in respect of its common units.

On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and the Partnership received proceeds of approximately $94.8 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

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 as of June 23, 2014 (the “Partnership Agreement”). The Partnership Agreement requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership’s behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership’s business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on its behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership.

Tax Sharing

In connection with the closing of the Viper Offering, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership’s results are included in a 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 consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership’s benefit, even though Diamondback had no cash tax expense for that period.

Other Agreements

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

The Partnership has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, (“Wells Fargo”) as administrative agent sole book runner and lead arranger. See Note 8–Debt for a description of this credit facility.

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Notes to Consolidated Financial Statements-(Continued)

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31, 2015	December 31, 2014
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$2,848,557	$2,345,077
Not subject to depletion-acquisition costs		
Incurred in 2015	433,769	—
Incurred in 2014	543,399	576,802
Incurred in 2013	68,351	130,474
Incurred in 2012	61,297	65,480
Incurred in 2011	—	764
Total not subject to depletion	1,106,816	773,520
Gross oil and natural gas properties	3,955,373	3,118,597
Accumulated depletion	(512,144)	(296,317)
Accumulated impairment	(897,962)	(83,164)
Oil and natural gas properties, net	2,545,267	2,739,116
Pipeline and gas gathering assets, net	7,174	7,174
Other property and equipment, net	48,621	48,180
Accumulated depreciation	(3,437)	(2,663)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$2,597,625	$2,791,807

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $15.2 million $11.4 million and $5.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

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

As a result of the significant decline in prices during 2015, the Company recorded non-cash ceiling test impairments for the year ended December 31, 2015 of $814.8 million, which is included in accumulated depletion. The Company did not have any impairment of its proved oil and natural gas properties during 2014. The impairment charge affected the Company’s reported net income but did not reduce its cash flow. In addition to commodity prices, the Company’s production rates, levels

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of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

6. ASSET RETIREMENT OBLIGATIONS

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

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Asset retirement obligation, beginning of period	$8,486	$3,029	$2,145
Additional liability incurred	594	703	226
Liabilities acquired	3,159	3,726	471
Liabilities settled	(292)	(27)	(14)
Accretion expense	833	467	201
Revisions in estimated liabilities	(69)	588	—
Asset retirement obligation, end of period	12,711	8,486	3,029
Less current portion	193	39	40
Asset retirement obligations - long-term	$12,518	$8,447	$2,989

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

7. EQUITY METHOD INVESTMENTS

In October 2014, the Company paid $0.6 million for a 25% in HMW Fluid Management LLC, which was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. The board of this entity may also authorize the entity to offer these services to other counties in the Permian Basin and to pursue other business opportunities. The Company has committed to invest an aggregate amount of $5.0 million in this entity, and several other third parties have committed to invest an aggregate of $15.0 million. For the year ended December 31, 2015, the Company invested an additional $2.7 million in this entity. The Company will retain a minority interest after all commitments are received. The entity was formed as a limited liability company and maintains a specific ownership account for each investor, similar to a partnership capital account structure. Therefore, the Company accounts for this investment under the equity method of accounting.

8. DEBT

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

	December 31,	
	2015	2014
	(in thousands)	
7.625 % Senior Notes due 2021	$450,000	$450,000

Revolving credit facility	$11,000	$223,500
Partnership revolving credit facility	34,500	—
Total long-term debt	$495,500	$673,500

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Notes to Consolidated Financial Statements-(Continued)

Senior Notes

On September 18, 2013, the Company completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the “Senior Notes”). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy Partners LLC as unrestricted subsidiaries and, upon such designation, Viper Energy Partners LLC, which was a guarantor under the indenture governing of the Senior Notes, was released as a guarantor under the indenture. As of December 31, 2015, the Senior Notes were fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin.

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

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

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

The Company’s Credit Facility

On June 9, 2014, Diamondback O&G LLC, as borrower, entered into a first amendment and on November 13, 2014, Diamondback O&G LLC entered into a second amendment to the second amended and restated credit agreement, dated November 1, 2013 (the “credit agreement”). The first amendment modified certain provisions of the credit agreement to, among other things, allow one or more of the Company’s subsidiaries to be designated as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Partnership, the General Partner and Viper Energy Partners LLC were designated as unrestricted subsidiaries under the credit agreement. As of December 31, 2015, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The second amendment increased the maximum amount of the credit facility to $2.0 billion, modified the dates and deadlines of the credit agreement relating to the scheduled borrowing base redeterminations based on the Company’s oil and

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natural gas reserves and other factors and added new provisions that allow the Company to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2015, the borrowing base was set at $750.0 million, of which the Company had elected a commitment amount of $500.0 million, and the Company had outstanding borrowings of $11.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent that the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750.0 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of December 31, 2015, the Company had $450.0 million of senior unsecured notes outstanding.

As of December 31, 2015 and December 31, 2014, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company’s revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

The Partnership’s Credit Agreement

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. On November 13, 2015, the borrowing base was increased from $175.0 million to $200.0 million. As of December 31, 2015, the borrowing base was set at $200.0 million. The Partnership had $34.5 million outstanding under its credit agreement.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-

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

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

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

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

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

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Interest expense	$40,221	$36,669	$10,322
Less capitalized interest	—	(5,275)	(3,951)
Other fees and expenses	1,292	3,121	1,688
Total interest expense	41,513	34,515	8,059

9. CAPITAL STOCK AND EARNINGS PER SHARE

As of December 31, 2015, Diamondback had completed the following equity offerings since the closing of its initial public offering on October 17, 2012:

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

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

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

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

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

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

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

In August 2015, the Company completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $68.74 per share and the Company received proceeds of approximately $197.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Earnings Per Share

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

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

	2015		
	Income	Shares	Per Share
	(in thousands, except per share amounts)		
Basic:			
Net income attributable to common stock	$(550,628)	63,019	$(8.74)
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	—	
Diluted:			
Net income attributable to common stock	$(550,628)	63,019	$(8.74)

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

	2014 Income	Shares	Per Share
	(in thousands, except per share amounts)		
Basic:			
Net income attributable to common stock	$193,755	52,826	$3.67
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	471	
Diluted:			
Net income attributable to common stock	$193,755	53,297	$3.64

	2013 Income	Shares	Per Share
	(in thousands, except per share amounts)		
Basic:			
Net income attributable to common stock	$54,587	42,015	$1.30
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	240	
Diluted:			
Net income attributable to common stock	$54,587	42,255	$1.29

For the year ended December 31, 2015, there were 100,924 shares that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods.

10. EQUITY-BASED COMPENSATION

On October 10, 2012, the Board of Directors approved the Diamondback Energy, Inc. 2012 Equity Incentive Plan (the “2012 Plan”), which is intended to provide eligible employees with equity-based incentives. The 2012 Plan provides for the granting of incentive stock options, nonstatutory stock options, restricted awards (restricted stock and restricted stock units), performance awards, and stock appreciation rights, or any combination of the foregoing. A total of 2,500,000 shares of the Company’s common stock has been reserved for issuance pursuant to this plan.

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

	2015	2014	2013
	(In thousands)		
General and administrative expenses	$18,529	$9,816	$1,752
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	6,043	4,437	972
Related income tax benefit	—	—	704

On June 17, 2014, in connection with the Viper Offering, the Board of Directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan (“Viper LTIP”), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. The Viper LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. A total of 9,144,000 common units has been reserved for issuance pursuant to the Viper LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The Viper LTIP is administered by the Board of Directors of the General Partner or a committee thereof.

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

Stock Options

In accordance with the 2012 Plan, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. The shares issued under the 2012 Plan will consist of new shares of Company stock. Unless otherwise specified in an agreement, options become exercisable ratably over a five-year period. However, as described above, options associated with the modification vest in four substantially equal annual installments and are exercisable for five years from the date of grant.

The fair value of the stock options on the date of grant is expensed over the applicable vesting period. The Company estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires the Company to make several assumptions. The Company does not have a long history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards and remaining vesting term at the modification date. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the option at the date of grant. The Company does not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero. All such amounts represent the weighted-average amounts for each year.

The following table presents a summary of the weighted average grant-date fair values and related assumptions for 2013. No stock options were granted during the years ended December 31, 2015 and 2014.

	2013	
Grant-date fair value	$6.51	
Expected volatility	36.9	%
Expected dividend yield	0.0	%
Expected term (in years)	3.8	
Risk-free rate	0.57	%

The following table presents the Company's stock option activity under the Company's 2012 Equity Incentive Plan ("2012 Plan") for the year ended December 31, 2015.

	Options		Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	313,105		$18.29		
Exercised	(273,605	)	$17.80		
Outstanding at December 31, 2015	39,500		$21.66	1.83	$1,787
Vested and Expected to vest at December 31, 2015	39,500		$21.66	1.83	$1,787
Exercisable at December 31, 2015	8,000		$17.50	0.78	$395

The aggregate intrinsic value of stock options that were exercised during the year ended December 31, 2015, 2014 and 2013 was $15.7 million, $22.0 million and $5.7 million, respectively. As of December 31, 2015, the unrecognized compensation cost related to unvested stock options was $0.1 million. Such cost is expected to be recognized over a weighted-average period of 1.1 years.

Restricted Stock Units

Under the 2012 Plan, approved by the Board of Directors, the Company is authorized to issue restricted stock and restricted stock units to eligible employees. The Company estimates the fair values of restricted stock awards and units as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable vesting period.

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

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

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	167,291	$49.99
Granted	138,534	$68.54
Vested	(143,956)	$42.58
Forfeited	(2,110)	$74.14
Unvested at December 31, 2015	159,759	$64.66

The aggregate fair value of restricted stock units that vested during the year ended December 31, 2015, 2014 and 2013 was $10.1 million, $8.2 million and $3.3 million, respectively. As of December 31, 2015, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $6.0 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

Performance-Based Restricted Stock Units

To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance-based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period.

In February 2014, eligible employees received initial performance restricted stock unit awards totaling 79,150 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2013 to December 31, 2015 and vested at December 31, 2015, subject to certification by the compensation committee that the performance standards were satisfied.

In February 2015, eligible employees received additional performance restricted stock unit awards totaling 90,249 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2014 to December 31, 2016 and cliff vest at December 31, 2016.

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

	2015	2014
Grant-date fair value	$137.14	$125.63
Risk-free rate	0.49%	0.30%
Company volatility	43.36%	39.60%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the year ended December 31, 2015.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	79,150	$125.63
Granted	90,249	$137.14
Vested	(79,150)	$125.63
Unvested at December 31, 2015 (1)	90,249	$137.14

(1) A maximum of 180,498 units could be awarded based upon the Company’s final TSR ranking.

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

As of December 31, 2015, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $6.5 million. Such cost is expected to be recognized over a weighted-average period of 1.0 year.

Partnership Unit Options

In accordance with the Viper LTIP, the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the Viper LTIP will consist of new common units of the Partnership. On June 17, 2014, the Board of Directors of the General Partner granted 2,500,000 unit options to the executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the first three anniversaries of the date of grant or earlier upon a change of control (as defined in the Viper LTIP). Vested unit options will be automatically exercised upon the earlier of a change of control or the third anniversary of the grant date unless extended in accordance with the terms of the Viper LTIP (the "Exercise Date"). In the event the fair market value per unit as of the exercise date is less than the exercise price per option unit then the vested options will automatically terminate and become null and void as of the exercise date.

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

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

The following table presents the unit option activity under the Viper LTIP for the year ended December 31, 2015.

	Unit Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	2,500,000	$26.00		
Granted	—	$—		
Outstanding at December 31, 2015	2,500,000	$—	1.50	$—
Vested and Expected to vest at December 31, 2015	2,500,000	$—	1.50	$—
Exercisable at December 31, 2015	—	$—	0.00	$—

As of December 31, 2015, the unrecognized compensation cost related to unvested unit options was $5.2 million. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Phantom Units

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

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

The following table presents the phantom unit activity under the Viper LTIP for the year ended December 31, 2015.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	17,776	$19.51
Granted	24,690	$15.48
Vested	(17,118)	$17.57
Unvested at December 31, 2015	25,348	$16.89

The aggregate fair value of phantom units that vested during the year ended December 31, 2015 was $0.3 million. As of December 31, 2015, the unrecognized compensation cost related to unvested phantom units was $0.3 million. Such cost is expected to be recognized over a weighted-average period of 1.2 years.

11. RELATED PARTY TRANSACTIONS

Immediately upon the completion of the Company's initial public offering on October 17, 2012, Wexford beneficially owned approximately 44% of the Company's outstanding common stock. As of December 31, 2015, Wexford beneficially owned less than 1% of the Company's outstanding common stock. A partner at Wexford serves as Chairman of the Board of Directors of each of the Company and the General Partner. Another partner at Wexford serves a member of the Board of Directors of the General Partner.

Administrative Services

An entity then under common management with the Company provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms continued on a month-to-month basis. Effective August 31, 2014, this agreement was mutually terminated. For the years ended December 31, 2014 and 2013, the Company incurred total costs of less than $0.1 million and $0.2 million, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. The Company had no outstanding amount payable at December 31, 2014 and owed the administrative services affiliate less than $0.1 million at December 31, 2013.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provided this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement was two years. Thereafter, the agreement continued on a month-to-month basis subject to the right of either party to terminate the agreement upon 30 days, prior written notice. Effective August 31, 2014, this agreement was mutually terminated. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the years ended December 31, 2014 and 2013, the affiliate reimbursed the Company $0.1 million and $1.1 million, respectively, for services under the shared services agreement. As of December 31, 2014, the affiliate owed the company less than $0.1 million. As of December 31, 2013, the affiliate had no outstanding amounts payable to the Company.

Drilling Services

Bison Drilling and Field Services LLC ("Bison"), an entity controlled by Wexford, has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. As of December 31, 2015 and December 31, 2014, the Company was not utilizing any Bison rigs. This master drilling agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. For the year ended December 31, 2015, the Company did not incur any costs for services performed by Bison. For the years ended December 31, 2014 and 2013, the Company incurred total costs for services performed by Bison of $3.5 million and $13.9 million, respectively. Bison is an affiliate of Wexford.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC, under which Panther Drilling Systems LLC provides directional drilling and other services. This master service agreement

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Notes to Consolidated Financial Statements-(Continued)

is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling Systems LLC's directional drilling services. For the year ended December 31, 2015, Panther Drilling Systems LLC did not perform any services for the Company. The Company incurred $0.3 million and $0.2 million for services performed for the years ended December 31, 2014 and 2013, respectively. Panther Drilling Systems LLC is an affiliate of Wexford.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC, formerly known as MidMar Gas LLC, an entity affiliated with Wexford, that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream LLC is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream LLC, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, Coronado Midstream LLC is obligated to pay the Company 87% of the net revenue received by Coronado Midstream LLC for all components of the Company's dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at Coronado Midstream LLC's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream LLC from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. An entity controlled by Wexford had owned approximately 28% equity interest in Coronado Midstream LLC until Coronado Midstream LLC was sold in March 2015. Coronado Midstream LLC is no longer a related party and any revenues, production and ad valorem taxes and gathering and transportation expense after March 2015 are not classified as those attributable to a related party. The Company recognized revenues from Coronado Midstream LLC of $5.2 million for the three months ended March 31, 2015. The Company recognized revenues from Coronado Midstream LLC of $24.4 million and $7.2 million for the years ended December 31, 2014 and 2013, respectively. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $1.1 million for the three months ended March 31, 2015. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $4.1 million and $1.2 million for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, Coronado Midstream owed the Company $4.0 million for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie Proppant LLC ("Muskie"), an entity affiliated with Wexford, processes and sells fracing grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company's requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days' notice. The Company did not incur any costs for sand purchased from Muskie for the years ended December 31, 2015 and 2014, respectively. The Company incurred costs of $0.7 million for sand purchased from Muskie for the year ended December 31, 2013. The Company had no outstanding amounts payable to Muskie as of December 31, 2015 or December 31, 2014.

Midland Leases

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $1.0 million, $0.4 million and $0.2 million for the years ended December 31, 2015, 2014 and 2013, respectively, under this lease.

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The following table contains information regarding recent amendments to the Midland corporate lease:

Date of Amendment	Reason for Amendment	Current Monthly Base Rent	New Monthly Base Rent or Rent for Additional Space	Approx. Annual Increase of Monthly Base Rent
2nd and 3rd quarters 2013(1)	Lease additional space	$13,000	$15,000	N/A
2nd quarter 2014	Lease additional space	$25,000	$27,000	N/A
4th quarter 2014(2)	Lease additional space	$27,000	$53,000	4%
November 2014(3)(4)	Extend the term	N/A	N/A	N/A
April 2015	Lease additional space	N/A	$23,000	N/A
June 2015	Lease additional space	N/A	$22,000	2%

(1) The monthly rent will increase further to $25,000 beginning on October 1, 2013.
(2) The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.
(3) The lease was amended to extend the term of the lease for an additional 10-year period.
(4) Upon commencement of the extension in June 2016, the monthly base rent will increase to $94,000, with an increase of approximately 2% annually.

Field Office Lease

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011 to March 1, 2014. Effective March 1, 2014, the building was purchased by an entity controlled by an affiliate of Wexford. The remaining term of the lease as of March 1, 2014 is four years. The Company paid rent of $0.2 million and $0.1 million to the related party for the years ended December 31, 2015 and 2014, respectively. The monthly base rent is $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term. During the third quarter of 2014, the Company negotiated a sublease with Bison, in which Bison will lease the field office space for the same term as the initial lease and will pay the monthly rent of $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term.

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $0.2 million and $0.2 million for the years ended December 31, 2014 and 2013, respectively, under this lease. Effective April 1, 2013, the Company amended this lease to increase the size of the leased premises, at which time the monthly base rent increased to $19,000 for the remainder of the lease term. The Company was also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises. Effective September 23, 2014, this lease agreement was mutually terminated.

Advisory Services Agreement - The Company

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on October 18, 2012, and continues for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of $1.2 million, $8.3 million and $0.5 million for the years ended December 31, 2015, 2014 and 2013, respectively, under the Advisory Services Agreement. For the year ended December 31, 2014, the total amount of $8.3 million was paid by cash payments of $4.3 million and the issuance to Wexford of 63,786 shares of the Company’s common stock.

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

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. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Partnership or the General Partner terminates such agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership and the General Partner have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner for such services as may be provided by Wexford at the Partnership's or the General Partner's request in connection with acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the Viper Advisory Services Agreement do not extend to the Partnership or the General Partners day-to-day business or operations. The Partnership and General Partner have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Viper Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. For the years ended December 31, 2015 and 2014, the Partnership incurred costs of $0.6 million and $0.3 million, respectively, under the Viper Advisory Services Agreement.

Secondary Offering Costs

On November 17, 2014, Gulfport Energy Corporation ("Gulfport") and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,000,000 shares of the Company's common stock and, on November 13, 2014, the underwriters purchased an additional 300,000 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the underwriters at $64.54 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of less than $0.1 million related to this secondary public offering.

On September 23, 2014, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,500,000 shares of the Company's common stock. The shares were sold to the underwriters at $75.44 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of $0.1 million related to this secondary public offering.

On June 27, 2014, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,000,000 shares of the Company's common stock. The shares were sold to the public at $90.04 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of approximately $0.1 million related to this secondary public offering.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of the Company's common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of approximately $0.2 million related to this secondary public offering.

12. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The Company is subject to corporate income taxes and the Texas margin tax.

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

The components of the provision for income taxes for the years ended December 31, 2015, 2014 and 2013 are as follows:

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Current income tax provision (benefit):			
Federal	$(33)	$—	$191
State	268	—	—
Total current income tax provision	235	—	191
Deferred income tax provision (benefit):			
Federal	(198,729)	106,107	30,768
State	(2,816)	2,878	795
Total deferred income tax provision (benefit)	(201,545)	108,985	31,563
Total provision for (benefit from) income taxes	$(201,310)	$108,985	$31,754

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Income tax expense (benefit) at the federal statutory rate (35%)	$(263,179)	$105,959	$30,231
Income tax expense (benefit) relating to change in tax rate	(1,145)	—	—
State income tax expense (benefit), net of federal tax effect	(2,548)	2,878	517
Non-deductible expenses and other	4,506	148	1,006
Change in valuation allowance	61,056	—	—
Provision for (benefit from) income taxes	$(201,310)	$108,985	$31,754

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

The components of the Company's deferred tax assets and liabilities as of December 31, 2015 and 2014 are as follows:

	December 31, 2015	2014
	(In thousands)	
Current:		
Deferred tax assets		
Derivative instruments	$—	$—
Other	2,658	1,950
Current deferred tax assets	2,658	1,950
Valuation allowance	(1,018)	—
Current deferred tax assets, net of valuation allowance	1,640	1,950
Deferred tax liabilities		
Derivative instruments	1,640	41,903
Total current deferred tax liabilities	1,640	41,903
Net current deferred tax assets	—	(39,953)
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards (subject to 20 year expiration)	82,635	49,627
Stock based compensation	3,873	2,520
Alternative minimum tax credit carryforward	—	33
Other	4,533	—
Noncurrent deferred tax assets	91,041	52,180
Valuation allowance	(60,038)	—
Noncurrent deferred tax assets, net of valuation allowance	31,003	52,180
Deferred tax liabilities		
Oil and natural gas properties and equipment	31,003	213,772
Other	—	—
Total noncurrent deferred tax liabilities	31,003	213,772
Net noncurrent deferred tax liabilities	—	161,592
Net deferred tax liabilities	$—	$201,545

The Company incurred a tax net operating loss ("NOL") in the current year due principally to the ability to expense certain intangible drilling and development costs under current law. There is no tax refund available to the Company, nor is there any current income tax payable. In light of the impairment of oil and gas properties, Management has recorded a $61.1 million valuation against the Company's federal NOLs. The valuation reduces the Company's deferred assets to a zero value, as management does not believe that it is more-likely-than-not that this portion of the Company's NOLs are realizable. Management believes that the balance of the Company's NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

The Company's U.S. federal NOLs and were incurred in the tax years 2015 and 2014, and will generally be available for use through the tax years 2035 and 2034, respectively. The State of Texas currently has no NOL carryover provision. The Company believes that Section 382 of the Internal Revenue Code of 1986, as amended, which relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three-year look back period, will not have an adverse effect on future NOL usage.

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

13. DERIVATIVES

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

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

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

As of December 31, 2015, the Company had open crude oil derivative positions with respect to future production as set forth in the table below. When aggregating multiple contracts, the weighted average contract price is disclosed.

Crude Oil—Inter–Continental Exchange Brent Fixed Price Swap		
Production Period	Volume (Bbls)	Fixed Swap Price
January - February 2016	91,000	88.72

Balance sheet offsetting of derivative assets and liabilities

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

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of December 31, 2015 and December 31, 2014.

	December 31,	
	2015	2014
	(in thousands)	
Gross amounts of recognized assets	$4,623	$117,541
Gross amounts offset in the Consolidated Balance Sheet	—	—

Net amounts of assets presented in the Consolidated Balance Sheet	$4,623	$117,541

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

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:

	December 31,	
	2015	2014
	(in thousands)	
Current Assets: Derivative instruments	$4,623	$115,607
Noncurrent Assets: Derivative instruments	—	1,934
Total Assets	$4,623	$117,541

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

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Change in fair value of open non-hedge derivative instruments	$(112,918)	$117,109	$5,346
Gain (loss) on settlement of non-hedge derivative instruments	144,869	10,430	(7,218)
Gain (loss) on derivative instruments	$31,951	$127,539	$(1,872)

14. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014.

	December 31, 2015	2014
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$—	$—
Significant other observable inputs level 2	4,623	117,541
Significant unobservable inputs level 3	—	—
Total	$4,623	$117,541

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$11,000	$11,000	$223,500	$223,500
7.625% Senior Notes due 2021	450,000	450,000	450,000	440,438
Partnership revolving credit facility	34,500	34,500	—	—

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the December 31, 2015 quoted market price, a Level 1 classification in the fair value hierarchy. The fair value of the Partnership's revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

15. COMMITMENTS AND CONTINGENCIES

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

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

Lease Commitments

The following is a schedule of minimum future lease payments with commitments that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2015:

Year Ending December 31,	Drilling Rig Commitments	Office and Equipment Leases
	(in thousands)	
2016	$29,536	$1,935
2017	19,893	2,053
2018	16,866	1,973
2019	589	1,839
2020	—	1,659
Thereafter	—	9,583
Total	$66,884	$19,042

The Company leases office space in Midland, Texas from related parties and office space in Oklahoma City, OK from an unrelated third party. Refer to Note 11—Related Party Transactions for further information on the related party lease agreements. The following table presents rent expense for the years ended December 31, 2015, 2014 and 2013.

	Year ended December 31,		
	2015	2014	2013
	(in thousands)		
Rent Expense	$1,449	$852	$571

Drilling contracts

As of December 31, 2015, the Company had entered into drilling rig contracts with one related party and various third parties in the ordinary course of business to ensure rig availability to complete the Company's drilling projects. Refer to Note 11–Related Party Transactions for further information on the related party drilling agreement. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2015 total approximately $66.9 million.

Oil production purchase agreement

On May 24, 2012, the Company entered into an oil purchase agreement with Shell Trading (US) Company, in which the Company is obligated to commence delivery of specified quantities of oil to Shell Trading (US) Company upon completion of the reversal of the Magellan Longhorn pipeline and its conversion for oil shipment, which occurred on October 1, 2013. The Company's agreement with Shell Trading has an initial term of 5 years from the completion date. The Company's maximum delivery obligation under this agreement is 8,000 gross barrels per day. The Company has a one-time right to elect to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased contract quantity will be effective for the remainder of the term of the agreement. The Company will receive the price per barrel of oil based on the arithmetic average of the daily settlement price for "Light Sweet Crude Oil" Prompt Month future contracts reported by the NYMEX over the one-month period, as adjusted based on adjustment formulas specified in the agreement. If the Company fails to deliver the required quantities of oil under the agreement during any three-month period following the service commencement date, the Company has agreed to pay

Shell Trading (US) Company a deficiency payment, which is calculated by multiplying (i) the volume of oil that the Company failed to deliver as required under the agreement during such period by (ii) Magellan's Longhorn Spot tariff rate in effect for transportation from Crane, Texas to the Houston Ship Channel for the period of time for which such deficiency volume is calculated. The agreement may be terminated by Shell Trading (US) Company in the event that Shell Trading (US) Company's contract for transportation on the pipeline is terminated.

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

Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allows eligible employees to contribute up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employer contributions vest in equal annual installments over a four year period. For the years ended December 31, 2015, 2014 and 2013 the Company paid $1.4 million, $0.4 million and $0.3 million, respectively, in contributions to the plan.

16. SUBSEQUENT EVENTS

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

17. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P LLC, Diamondback O&G LLC and White Fang Energy LLC (the "Guarantor Subsidiaries") are guarantors under the Indenture relating to the Senior Notes. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy Partners LLC (the "Non-Guarantor Subsidiaries") as unrestricted subsidiaries under the Indenture and, upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 17 is referred to as the "Parent"), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries on a consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

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

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

	Parent	Guarantor Subsidiaries	Non– Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$148	$19,428	$539	$—	$20,115
Restricted cash	—	—	500	—	500
Accounts receivable	—	67,942	9,369	2	77,313
Accounts receivable - related party	—	1,591	—	—	1,591
Intercompany receivable	2,246,846	205,915	—	(2,452,761)	—
Inventories	—	1,728	—	—	1,728
Other current assets	450	6,572	476	—	7,498
Total current assets	2,247,444	303,176	10,884	(2,452,759)	108,745
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	3,400,381	554,992	—	3,955,373
Pipeline and gas gathering assets	—	7,174	—	—	7,174
Other property and equipment	—	48,621	—	—	48,621
Accumulated depletion, depreciation, amortization and impairment	—	(1,347,296)	(71,659)	5,412	(1,413,543)
Net property and equipment	—	2,108,880	483,333	5,412	2,597,625
Investment in subsidiaries	79,417	—	—	(79,417)	—
Other assets	7,795	8,733	35,514	—	52,042
Total assets	$2,334,656	$2,420,789	$529,731	$(2,526,764)	$2,758,412
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$20,007	$1	$—	$20,008
Accounts payable-related party	1	212	4	—	217
Intercompany payable	—	2,452,759	—	(2,452,759)	—
Other current liabilities	8,683	112,431	82	—	121,196
Total current liabilities	8,684	2,585,409	87	(2,452,759)	141,421
Long-term debt	450,000	11,000	34,500	—	495,500
Asset retirement obligations	—	12,518	—	—	12,518
Total liabilities	458,684	2,608,927	34,587	(2,452,759)	649,439
Commitments and contingencies					
Stockholders' equity:	1,875,972	(188,138)	495,144	(307,006)	1,875,972
Noncontrolling interest	—	—	—	233,001	233,001
Total equity	1,875,972	(188,138)	495,144	(74,005)	2,108,973
Total liabilities and equity	$2,334,656	$2,420,789	$529,731	$(2,526,764)	$2,758,412

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

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

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

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$336,106	$—	$69,609	$405,715
Natural gas sales	—	16,932	—	2,660	19,592
Natural gas liquid sales	—	18,836	—	2,590	21,426
Royalty income	—	—	74,859	(74,859)	—
Total revenues	—	371,874	74,859	—	446,733
Costs and expenses:					
Lease operating expenses	—	82,625	—	—	82,625
Production and ad valorem taxes	—	27,459	5,531	—	32,990
Gathering and transportation	—	5,832	259	—	6,091
Depreciation, depletion and amortization	—	182,395	35,436	(134)	217,697
Impairment of oil and natural gas properties	—	814,798	3,423	(3,423)	814,798
General and administrative expenses	17,077	9,056	5,835	—	31,968
Asset retirement obligation accretion expense	—	833	—	—	833
Total costs and expenses	17,077	1,122,998	50,484	(3,557)	1,187,002
Income (loss) from operations	(17,077)	(751,124)	24,375	3,557	(740,269)
Other income (expense)					
Interest expense	(35,651)	(4,749)	(1,110)	—	(41,510)
Other income	1	(588)	1,154	—	567
Other income - intercompany	—	161	—	—	161
Gain (loss) on derivative instruments, net	—	31,951	—	—	31,951
Total other income (expense), net	(35,650)	26,775	44	—	(8,831)
Income (loss) before income taxes	(52,727)	(724,349)	24,419	3,557	(749,100)
Benefit from income taxes	(201,310)	—	—	—	(201,310)
Net income (loss)	148,583	(724,349)	24,419	3,557	(547,790)
Less: Net income attributable to noncontrolling interest	—	—	—	2,838	2,838
Net income (loss) attributable to Diamondback Energy, Inc.	$148,583	$(724,349)	$24,419	$719	$(550,628)

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$377,712	$—	$71,532	$449,244
Natural gas sales	—	15,240	—	2,788	18,028
Natural gas liquid sales	—	24,545	—	3,901	28,446
Royalty income	—	—	77,767	(77,767)	—
Total revenues	—	417,497	77,767	454	495,718
Costs and expenses:					
Lease operating expenses	—	55,384	—	—	55,384
Production and ad valorem taxes	—	27,242	5,377	19	32,638
Gathering and transportation	—	3,294	—	(6)	3,288
Depreciation, depletion and amortization	—	143,477	27,601	(1,073)	170,005
General and administrative expenses	10,879	7,189	4,372	(1,174)	21,266
Asset retirement obligation accretion expense	—	467	—	—	467
Total costs and expenses	10,879	237,053	37,350	(2,234)	283,048
Income (loss) from operations	(10,879)	180,444	40,417	2,688	212,670
Other income (expense)					
Interest income - intercompany	10,755	—	—	(10,755)	—
Interest expense	(30,281)	(3,746)	(487)	—	(34,514)
Interest expense - intercompany	—	—	(10,755)	10,755	—
Other income	6	91	459	—	556
Other income - intercompany	—	1,027	—	(906)	121
Other expense	—	(1,416)	—	—	(1,416)
Loss on derivative instruments, net	—	127,539	—	—	127,539
Total other income (expense), net	(19,520)	123,495	(10,783)	(906)	92,286
Income before income taxes	(30,399)	303,939	29,634	1,782	304,956
Provision for income taxes	108,985	—	—	—	108,985
Net income (loss)	$(139,384)	$303,939	$29,634	$1,782	$195,971
Less: Net income attributable to noncontrolling interest	—	—	—	2,216	2,216
Net income (loss) attributable to Diamondback Energy, Inc.	$(139,384)	$303,939	$29,634	$(434)	$193,755

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$174,868	$—	$13,885	$188,753
Natural gas sales	—	5,852	—	397	6,249
Natural gas liquid sales	—	12,295	—	705	13,000
Royalty income	—	—	14,987	(14,987)	—
Total revenues	—	193,015	14,987	—	208,002
Costs and expenses:					
Lease operating expenses	—	21,157	—	—	21,157
Production and ad valorem taxes	—	11,927	972	—	12,899
Gathering and transportation	—	918	—	—	918
Depreciation, depletion and amortization	—	61,398	5,199	—	66,597
General and administrative expenses	3,909	7,127	—	—	11,036
Asset retirement obligation accretion expense	—	201	—	—	201
Intercompany charges	—	—	87	(87)	—
Total costs and expenses	3,909	102,728	6,258	(87)	112,808
Income (loss) from operations	(3,909)	90,287	8,729	87	95,194
Other income (expense)					
Interest income - intercompany	5,741	—	—	(5,741)	—
Interest expense	(591)	(7,467)	(5,741)	5,741	(8,058)
Other income	—	87	—	(87)	