Diamondback Energy, Inc.
Form 10-K
February 25, 2019
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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, 2018

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 (Address of Principal Executive Offices)	79701 (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 every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	ý	Accelerated Filer	¨
Non-Accelerated Filer	¨	Smaller Reporting Company	¨
		Emerging Growth Company	o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 29, 2018 was approximately $11,455,114,815.

As of February 15, 2019, 164,381,522 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2019 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K

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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.
Mb/d	Thousand barrels per day.
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 of natural gas 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.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
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.

Bison	Bison Drilling and Field Services, LLC.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
EPA	U.S. Environmental Protection Agency.
Equity Plan	The Company's Equity Incentive Plan.
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.
2024 Indenture	The indenture relating to the 2024 Senior Notes, dated as of October 28, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
2025 Indenture	The indenture relating to the 2025 Senior Notes, dated as of December 20, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
Operating Company	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of the Partnership.
OSHA	Federal Occupational Safety and Health Act.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
2024 Senior Notes	The Company's 4.750% senior unsecured notes due 2024 in the aggregate principal amount of $1,250 million.
2025 Senior Notes	The Company's 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $800 million.
Senior Notes	The 2024 Senior Notes and the 2025 Senior Notes.
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 and Section 21E of the Securities Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are int 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, including our recent acquisition of certain leasehold acres and other assets from Ajax Resources, LLC and our recent acquisition of Energen Corporation discussed elsewhere in this report;
- our ability to achieve the anticipated synergies, operational efficiencies and returns from our recent acquisition of Energen Corporation;
- 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, 2018, our total acreage position in the Permian Basin was approximately 604,367 gross (461,218 net) acres, which consisted primarily of approximately 231,100 gross (194,661 net) acres in the Midland Basin and approximately 232,143 gross (170,205 net) acres in the Delaware Basin. In addition, we, through our publicly traded subsidiary Viper Energy Partners LP, which we refer to as Viper or the Partnership, own mineral interests underlying approximately 532,295 gross acres and 14,841 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 37% of these net royalty acres are operated by us. We own Viper Energy Partners GP LLC, the general partner of Viper, which we refer to as the general partner, and we own approximately 59% of the limited partner interest in Viper.

Our activities are primarily focused on horizontal development of the Spraberry and Wolfcamp formations of the Midland Basin and the Wolfcamp and Bone Spring formations of the Delaware Basin, both of which are part of the larger Permian Basin in West Texas and New Mexico. The Permian Basin 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.

As of December 31, 2018, our estimated proved oil and natural gas reserves were 992,001 MBOE (which includes estimated reserves of 63,136 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 65% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 416 gross (374 net) horizontal well locations in which we have a working interest, and 25 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2018, our estimated proved reserves were approximately 63% oil, 18% natural gas liquids and 19% natural gas.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 11,868 gross (7,633 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $60.00 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.

Merger with Energen Corporation and Other Significant 2018 Transactions

Merger with Energen Corporation

On November 29, 2018, we completed our acquisition of Energen Corporation, or Energen, in an all-stock transaction, which we refer to as the merger. The addition of Energen's assets increased our assets to: (i) over 273,000 net Tier One acres in the Permian Basin, an increase of 57% from third quarter 2018 Tier One acreage of approximately 174,000 net acres, (ii) over 7,200 estimated total net horizontal Permian locations, an increase of over 120% from third quarter 2018 estimated net locations, and (iii) approximately 394,000 net acres across the Midland and Delaware Basins.

Ajax Resources, LLC

On October 31, 2018, we acquired certain leasehold interests and related assets of Ajax Resources, LLC, which we refer to as Ajax, which acquisition included approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900.0 million in cash, subject to certain adjustments, and approximately 2.6 million shares of our common stock, which we refer to as the Ajax acquisition. The Ajax acquisition was effective as of July 1, 2018.

ExL Petroleum Management, LLC and EnergyQuest II LLC Acquisition

On October 31, 2018, we acquired certain leasehold interests and related assets of ExL Petroleum Management, LLC, ExL Petroleum Operating, Inc. and EnergyQuest II LLC, which included an aggregate of approximately 3,646 net leasehold acres in the Northern Midland Basin, for a total of $312.5 million in cash, subject to certain adjustments. These acquisitions, which we collectively refer to as the ExL acquisition, were effective as of August 1, 2018.

Drop-down Transaction

On August 15, 2018, we sold to Viper mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by us, for $175.0 million, which we refer to as the Drop-down Transaction.

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 development of stacked horizons. We have been developing multiple pay intervals in the Permian Basin through horizontal drilling and believe that there are opportunities to target additional intervals throughout the stratigraphic column. Our initial horizontal wells were completed in 2012, and since then we have been an active horizontal driller in the basin. As of December 31, 2018, we are the operator of 1,193 producing horizontal wells and have a non-operated working interest in 253 additional wells. Of these 1,446 total horizontal wells, 952 wells are in the Midland Basin, 493 wells are in the Delaware Basin and one well is in the Central Basin platform. We believe that our significant experience drilling, completing and operating horizontal wells will allow us to efficiently develop our remaining inventory and ultimately target other horizons that have limited development to date. During the year ended December 31, 2018, we were able to drill our horizontal wells in the Midland Basin with approximately 7,500 foot lateral lengths to total depth, or TD, in an average of 13 days, we drilled approximately 10,000 foot lateral wells in 15 days and we drilled approximately 13,000 foot wells in 23 days. During the year ended December 31, 2018, we were able to drill our horizontal wells in the Delaware Basin with approximately 7,500 foot lateral lengths to total depth in an average of 24 days and we drilled approximately 10,000 foot lateral wells in 31 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 89% 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 76% 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, 2018, we completed multiple acquisitions in the Midland Basin through our acquisitions of Ajax, ExL and EnergyQuest, as well as Energen. As a result, our Midland Basin acreage footprint increased from approximately 101,941 net acres to approximately 194,661 net acres as of December 31, 2018, with our Delaware Basin acreage increasing from approximately 104,719 net acres to approximately 170,205 net acres over the same period.

- Maintain financial flexibility. We seek to maintain a conservative financial position. In connection with our fall 2018 borrowing base redetermination, our borrowing base was set at $2.65 billion, and we elected a commitment amount of $2.0 billion, of which $0.5 billion was available for borrowing as of December 31, 2018. As of December 31, 2018, Viper had $411.0 million in outstanding borrowings, and $144.0 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 Permian Basin. Our production for the year ended December 31, 2018 was approximately 72% oil, 16% natural gas liquids and 12% natural gas. As of December 31, 2018, our estimated net proved reserves were comprised of approximately 63% oil, 18% natural gas liquids and 19% natural gas.

- 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 $60.00 per Bbl WTI, we currently have approximately 11,868 gross (7,633 net) identified economic potential horizontal drilling locations on our acreage based on our evaluation of applicable geologic and engineering data. These gross identified economic potential horizontal locations have an average lateral length of approximately 7,200 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 11,868 locations, 6,479 are in the Midland Basin and 5,389 are in the Delaware Basin. In the Midland Basin, 2,465 are in the Lower Spraberry or Wolfcamp B horizons where we have drilled a large number of wells, 2,200 are in the Wolfcamp A or Middle Spraberry horizons where we have drilled a limited number of wells and 1,814 are in the Clearfork, Jo Mill or Cline horizons where we have drilled very few wells. Our current location count for the Lower Spraberry horizon is based on 660 foot to 880 foot spacing in Midland, Martin, northeast Andrews, Howard and Glasscock counties, depending on the prospect area and 880 foot spacing in all other counties. For the Wolfcamp B horizon, the horizontal location count is based on 660 foot to 880 foot spacing between wells in Midland, Martin, northeast Andrews, Howard, and Glasscock counties, and 880 foot spacing in all other counties. In the Wolfcamp A horizon, the horizontal location count in based on 660 foot to 880 foot spacing in Midland, Howard and Glasscock counties, 880 foot spacing in southwest Martin county and 1,320 foot spacing in other counties. The horizontal location count for the Middle Spraberry is based on 880 foot spacing in Midland, Martin and northeast Andrews counties and 1,320 foot spacing in other counties. In the Cline and Clearfork and Jo Mill horizons, the horizontal location count is based on 880 foot to 1,320 foot spacing. In the Delaware Basin, 2,219 locations are in the Wolfcamp A or Wolfcamp B horizons, and 1,789 locations are in the 2nd Bone Spring or 3rd Bone Spring horizon and 1,381 locations are in other horizons including the Brushy Canyon, Avalon, 1st Bone Spring and Wolfcamp C. The horizontal location counts are based on 880 foot spacing in the Wolfcamp A and Wolfcamp B horizons, and 1,320 foot spacing in the Bone Spring horizons. The ultimate inter-well spacing may vary from these distances due to different factors, which would result in a higher or lower location count. In addition, we have approximately 2,617 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 in addition to 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 longest operating 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 89% 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 acreage position in the Permian Basin was approximately 604,367 gross (461,218 net) acres, which consisted primarily of approximately 231,100 gross (194,661 net) acres in the Midland Basin and approximately 232,143 gross (170,205 net) acres in the Delaware Basin at December 31, 2018. We are the operator of approximately 89% of this Permian Basin acreage. In addition, we, through our subsidiary Viper, own mineral interests underlying approximately 532,295 gross acres and 14,841 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 37% of these net royalty acres are operated by us. 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, Bone Spring, 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. Since then we and most other operators are almost exclusively drilling horizontal wells in the development of unconventional reservoirs in the Permian Basin. As of December 31, 2018, we held working interests in 7,279 gross (4,678 net) producing wells and only royalty interests in 2,645 additional wells.

Geology

The Permian Basin formed as an area of rapid Pennsylvanian-Permian subsidence in response to dynamic structural influence. It is one of the largest sedimentary basins in the U.S., with established 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. Time equivalent in the Delaware Basin, the "Wolfbone" play describes vertically commingled production from the Permian Bone Spring and Wolfcamp formations.

The Spraberry/Bone Spring was deposited as siliciclastic 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/Bone Spring 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 and Wolfbone are unconventional "basin-centered oil" resource plays, in the sense that there is no regional downdip oil/water contact.

We have successfully developed several shale intervals within the Clearfork, Spraberry/Bone Spring and Wolfcamp formations since we began horizontal drilling in 2012. The shales exhibit low permeabilities which necessitate the need for hydraulic fracture stimulation to unlock the vast storage of hydrocarbons in these targets.

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 2,617 square miles of 3-D data. This data will continue to be utilized in the development of our horizontal drilling program and identification of additional resource to be exploited.

Production Status

During the year ended December 31, 2018, net production from our Permian Basin acreage was 47,610 MBOE, or an average of 130,439 BOE/d, of which approximately 72% was oil, 16% was natural gas liquids and 12% 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.

Recent and Future Activity

During 2019, we expect to complete an estimated 290 to 320 gross (255 to 280 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2019 for drilling and infrastructure will be between $2.7 billion and $3.0 billion, consisting of $2.3 billion to $2.55 billion for horizontal drilling and completions including non-operated activity, $400.0 million to $450.0 million for midstream and infrastructure investments, excluding equity investments in long-haul pipelines or the cost of any leasehold and mineral rights acquisitions. During the year ended December 31, 2018, we drilled 189 gross (168 net) and completed 176 gross (155 net) operated horizontal wells. During the year ended December 31, 2018, our capital expenditures for drilling, completing and equipping wells were $1.4 billion. In addition, we spent $306.4 million for oil and gas midstream and infrastructure and $1.8 billion for leasehold and mineral rights acquisitions.

We are operating 21 rigs now and currently intend to operate between 18 and 22 rigs in 2019. 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.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2018, 2017 and 2016 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, 2018 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 87% 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 13% 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 Executive Vice President–Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Executive 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 19 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 Executive Vice President–Reservoir Engineering or under his direct supervision;
- review by our Executive 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 Executive 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, 2018, 2017 and 2016 (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,		
	2018	2017	2016
Estimated proved developed reserves:			
Oil (MBbls)	403,051	141,246	79,457
Natural gas (MMcf)	705,084	190,740	105,399
Natural gas liquids (MBbls)	125,509	35,412	22,080
Total (MBOE)	646,074	208,447	119,104
Estimated proved undeveloped reserves:			
Oil (MBbls)	223,885	91,935	59,717
Natural gas (MMcf)	343,565	94,629	69,497
Natural gas liquids (MBbls)	64,782	19,198	15,054
Total (MBOE)	345,928	126,905	86,354
Estimated Net Proved Reserves:			
Oil (MBbls)	626,936	233,181	139,174
Natural gas (MMcf)	1,048,649	285,369	174,896
Natural gas liquids (MBbls)	190,291	54,609	37,134
Total (MBOE)(1)	992,001	335,352	205,458
Percent proved developed	65 %	62 %	58 %

(1) Estimates of reserves as of December 31, 2018, 2017 and 2016 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, 2018, 2017 and 2016, 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, 2018, our proved undeveloped reserves totaled 223,885 MBbls of oil, 343,565 MMcf of natural gas and 64,782 MBbls of natural gas liquids, for a total of 345,928 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 2018:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2017	126,905
Undeveloped reserves transferred to developed	(71,435)
Revisions	338
Net purchases	165,426
Extensions and discoveries	124,694
Ending proved undeveloped reserves at December 31, 2018	345,928

The increase in proved undeveloped reserves was primarily attributable to purchases of 165,426 MBOE mostly from the acquisition of Energen. Extensions contributed 111,020 MBOE from 138 gross (122 net) wells in which we have a working interest and 13,674 MBOE from 138 gross wells in which Viper owns royalty interests. Of the 138 gross working interest wells, 38 were in the Delaware Basin. Transfers of 71,435 MBOE were the result of drilling or participating in 89 gross (79 net) horizontal wells in which we have a working interest and 49 gross wells in which we have a royalty interest or mineral interest through Viper. We own a working interest in 45 of the 49 gross Viper wells. Upward revisions of 338 MBOE resulted from commodity price improvement and type curve performance.

Costs incurred relating to the development of PUDs were approximately $493.1 million during 2018. Estimated future development costs relating to the development of PUDs are projected to be approximately $1,201.7 million in 2019, $1,121.4 million in 2020, $435.1 million in 2021 and $127.0 million in 2022. 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.

As of December 31, 2018, 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, 2018, 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:

	Year Ended December 31,		
	2018	2017	2016
Production Data:			
Oil (MBbls)	34,367	21,418	11,562
Natural gas (MMcf)	34,669	20,660	10,728
Natural gas liquids (MBbls)	7,465	4,056	2,399
Combined volumes (MBOE)	47,610	28,917	15,749
Daily combined volumes (BOE/d)	130,439	79,224	43,031
Average Prices:			
Oil (per Bbl)	$54.66	$48.75	$40.70
Natural gas (per Mcf)	1.76	2.53	2.10
Natural gas liquids (per Bbl)	25.47	22.20	14.20
Combined (per BOE)	44.73	41.02	33.47
Oil, hedged ($ per Bbl)(1)	51.20	48.94	40.80
Natural gas, hedged ($ per MMbtu)(1)	1.72	2.65	2.06
Average price, hedged ($ per BOE)(1)	42.20	41.26	33.54
Average Costs per BOE:			
Lease operating expense	$4.31	$4.38	$5.23
Production and ad valorem taxes	2.79	2.54	2.19
Gathering and transportation expense	0.55	0.44	0.74
General and administrative - cash component	0.79	0.80	1.03
Total operating expense - cash	$8.44	$8.16	$9.19
General and administrative - non-cash component	$0.57	$0.88	$1.68
Depreciation, depletion and amortization	13.09	11.30	11.30
Interest expense, net	1.83	1.40	2.58
Merger and integration expense	0.77	—	—
Total expenses	$16.26	$13.58	$15.56

(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, 2018, we owned an average unweighted 64% working interest in 7,279 gross (4,678 net) productive wells and an average 0.5% royalty interest in 2,645 additional wells. Through our subsidiary Viper, we own an average unweighted 4.3% royalty or mineral interest in 3,448 productive wells. 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, 2018 relating to our leasehold acreage:

Basin	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage(3)	
	Gross(4)	Net(5)	Gross(4)	Net(5)	Gross(4)	Net(5)
Conventional Permian	103,155	70,410	14,795	4,178	117,950	74,588
Delaware	127,819	90,554	104,324	79,651	232,143	170,205
Exploration	—	—	23,174	21,764	23,174	21,764
Midland	198,408	162,370	32,692	32,291	231,100	194,661
Total	429,382	323,334	174,985	137,884	604,367	461,218

(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 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, 2018, 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.

Basin	2019		2020		2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Delaware	43,963	31,130	13,779	6,474	7,447	3,447	—	—	—	—
Exploration	—	—	18,713	18,713	4,405	3,035	—	—	—	—
Midland	9,246	6,406	4,443	2,503	172	385	308	254	—	—
Total	53,209	37,536	36,935	27,690	12,024	6,867	308	254	—	—

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,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	88	78	27	23	6	3
Dry	—	—	—	—	—	—
Exploratory:						
Productive	88	78	112	84	82	62
Dry	—	—	—	—	—	—
Total:						
Productive	176	156	139	107	88	65
Dry	—	—	—	—	—	—

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, 2018, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (26%); Koch Supply & Trading LP (15%); and Occidental Energy Marketing Inc (11%). For the year ended December 31, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (31%); Koch Supply & Trading LP (19%); and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2016, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (45%); Koch Supply & Trading LP (15%); and Enterprise Crude Oil LLC (13%). 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.

Agreement with Trafigura Trading LLC

We have entered into a firm commitment oil purchase agreement with Trafigura Trading LLC, which we refer to as Trafigura, in which we agreed to sell and deliver an average of 25,000 barrels per day of Midland Sweet Crude Oil (WTI) to Trafigura during the term of the agreement. Under this agreement, which has a seven-year term beginning on August 1, 2018, the price per barrel of oil paid to us by Trafigura is based on the average of the published settlement quotations for NYMEX CMA, as adjusted for different delivery methods and periods. If during the term of the agreement we fail to deliver the required quantities of oil for any month other than for specified force majeure events, we have agreed to pay Trafigura a deficiency payment equal to any unfavorable difference between the contract price and the spot price, multiplied by the deficiency volume.

Agreement with Shell Trading (US) Company

We were party to a five-year oil purchase agreement with Shell Trading (US) Company that expired on September 30, 2018. In December 2018, we entered into a new oil purchase agreement with Shell Trading (US) Company in which Shell Trading (US) Company agreed to transport crude petroleum it purchases from us through the Epic Crude Pipeline, with which we have an agreement for the transportation of a maximum quantity of 50,000 barrels of crude petroleum per day. Our agreement with Shell Trading (US) Company provides for different purchase obligations during the pre-commencement and service commencement periods for the Epic Crude Pipeline, and provides for a three-year term beginning on the service commencement date for the Epic Crude Pipeline. Shell Trading (US) Company has the option to extend its purchase obligations for up to two one-year terms. Our delivery obligations during the pre-commencement terms range from 30,000 to 40,000 barrels per day and, during the full service term, our maximum delivery obligation is 50,000 barrels per day, determined based on the amount of crude petroleum we are obligated to transport on the EPIC Crude Pipeline under our transportation agreement with such pipeline. During different pre-commencement periods, Shell Trading (US) Company has agreed to pay 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, subject to agreed adjustments, or a specified price. During the full service term, the price per barrel of oil payable by Shell Trading (US) Company to us is subject to negotiation.

Agreement with Vitol Inc.

We have also entered into an oil purchase agreement with Vitol Inc., which we refer to as Vitol. The agreement provides for different delivery obligations before and after the Gray Oak Pipeline is in full service, ranging from 23,750 barrels per day during the period from November 1, 2018 to September 30, 2019, to 50,000 barrels per day (up to a maximum of 100,000 barrels per day) once the Gray Oak Pipeline is in full service, determined based on the amount of crude petroleum we are obligated to transport on the Gray Oak Pipeline under our transportation agreement with such pipeline. The agreement with Vitol provides for a seven-year term commencing on the date when the Gray Oak Pipeline is in full service. The agreement contemplates variable prices depending on the delivery periods specified in the agreement. The agreement also provides for a five-year term commencing on the date the EPIC Crude Pipeline is ready to perform transportation services from the EPIC Midway Terminal, during which we agreed to sell crude petroleum to Vitol opportunistically at negotiated prices. If we fail to deliver any required quantities of oil for any month other than for specified force majeure events, we have agreed to pay Vitol a deficiency payment equal to any unfavorable difference between the contract price and the price paid by Vitol to third parties to replace the deficiency quantity, multiplied by the deficiency quantity, subject to certain other adjustments.

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 in the Midland Basin is transported to purchasers by pipeline. During 2019, several oil and saltwater disposal gathering systems were installed. We believe that these gathering systems will help us reduce our lease operating expense and improve our margins on sales in future periods.

The following table presents the average percentage of produced oil sold by pipeline and the average percentage of produced water connected to saltwater disposals by pipeline:

	Midland Basin	Delaware Basin	Total
% of produced oil sold by pipeline	94 %	68 %	88 %
% of produced water connected to pipeline	94 %	92 %	93 %

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 12.50% to 30.00%, resulting in a net revenue interest to us generally ranging from 70.00% to 87.50%.

Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while 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 related to our owned or operated facilities. Liability under such laws and regulations is often 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 and 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 non-hazardous waste requirements. 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.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. 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 impose 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. 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. 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. On June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or the Corps, jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. The rules are subject to ongoing litigation and have been stayed in more than half the States, including Texas. Also, on December 11, 2018, the EPA and the Corps released a proposed rule that would replace the 2015 rule, and significantly reduce the waters subject to federal regulation under the Clean Water Act. Such proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act.

To the extent the rule expands the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

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 June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants, 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.

Non-compliance 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." Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. 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. In May 2010, the EPA adopted regulations establishing new greenhouse gas emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or 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 August 26, 2016, the EPA proposed changes needed to bring the EPA's air permitting regulations in line with the Supreme Court's decision on greenhouse gas permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

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.

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.

At the international level, in December 2015, the United States participated in 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 went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. 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, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, 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 or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such 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 hotter or 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, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection,” to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has 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.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural 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 rules seek 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 particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. Also, on October 15, 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites. The above standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. 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 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 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 rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The 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 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 plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. Although the Corps 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.

Natural Gas Gathering. Although FERC has not made a formal determination with respect to the facilities we consider to be natural gas gathering pipelines, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that pipelines perform primarily a gathering function and are, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated interstate transportation services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the Natural Gas Act of 1938, or NGA, and that the facility provides interstate transportation service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the Natural Gas Policy Act, or NGPA. Such regulation could decrease revenue, increase operating costs and, depending upon the facility in question, adversely affect our results of operations and cash flow. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

Even though we consider our natural gas gathering pipelines to be exempt from the jurisdiction of FERC under the NGA, FERC regulation of interstate natural gas transportation pipelines may indirectly impact gathering services. FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release and market center promotion may indirectly affect intrastate markets and gathering services. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the natural gas gathering services.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and

services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased operating costs depending on future legislative and regulatory changes.
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 our subsidiary Rattler Midstream Operating LLC has a tariff on file with FERC to perform gathering service in interstate commerce. 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, including our subsidiary Rattler Midstream Operating LLC, 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, 2018, we had approximately 711 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 Birmingham, Alabama, Houston, Texas, Midland, Texas and 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 SEC. 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 Properties” 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 condition or results of operations and the trading price of our shares could decline.

Risk Related to Our Recently Completed Merger with Energen

The integration of Energen’s business into our business may not be as successful as anticipated, and we may not achieve the intended benefits of the merger or do so within the intended timeframe.
We completed the merger with Energen on November 29, 2018. The merger involves numerous operational, strategic, financial, accounting, legal, tax and other risks, including potential liabilities associated with the acquired business. Difficulties in integrating Energen’s business into our business, and our ability to manage the combined company, may result in the combined company performing differently than expected, in operational challenges or in the delay or failure to realize anticipated expense-related efficiencies, and could have an adverse effect on our financial condition, results of operations or cash flows. Potential difficulties that may be encountered in the integration process include, among other factors:

- the inability to successfully integrate the businesses of Energen into our business, operationally and culturally;
- complexities associated with managing the larger, more complex, integrated business;
- complexities resulting from the different accounting methods of our company and Energen;
- not realizing anticipated operating synergies;
- integrating personnel from the two companies and the loss of key employees;
- potential unknown liabilities and unforeseen expenses associated with the merger or integration;
- integrating relationships with customers, vendors and business partners;
- performance shortfalls as a result of the diversion of management’s attention caused by integrating Energen’s operations into operations; and

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- the disruption of, or the loss of momentum in, our business or inconsistencies in standards, controls, procedures and policies encountered during integration of our business with that of Energen.

Additionally, the success of the merger will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and Energen’s businesses, including operational and other synergies that we believe the combined company will achieve. The anticipated benefits and cost savings of the merger may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that we do not currently foresee.

Our results may suffer if we do not effectively manage our expanded operations following the merger.

Following the merger, the size of our business increased significantly beyond the former size of our business. Our future success will depend, in part, on our ability to manage this expanded business, which poses numerous risks and uncertainties, including the need to integrate the operations and business of Energen into our business in an efficient and timely manner, to combine systems and management controls and to integrate relationships with customers, vendors and business partners. Failure to successfully manage the combined company may have an adverse effect on our financial condition, results of operations or cash flows.

Sales of substantial amounts of our common stock in the open market, by former Energen shareholders or otherwise, could depress our common stock price.

Our stockholders may not wish to continue to invest in the additional operations of the combined company, or for other reasons may wish to dispose of some or all of their interests in the combined company, and as a result may seek to sell their shares of our common stock. Shares of our common stock that were issued to the former holders of Energen common stock in the merger are freely tradable by such stockholders without restrictions or further registration under the Securities Act of 1933, which we refer to as the Securities Act, provided, however, that any stockholders who are our affiliates will be subject to the resale restrictions of Rule 144 under the Securities Act. These sales (or the perception that these sales may occur), coupled with the increase in the outstanding number of shares of our common stock, may affect the market for, and the market price of, our common stock in an adverse manner. In the merger, we issued approximately 62.8 million shares of our common stock to Energen shareholders. As of February 15, 2019, we had approximately 164,381,522 shares of common stock outstanding and approximately 77,659 shares of common stock subject to unvested restricted stock units outstanding.

If our stockholders sell substantial amounts of our common stock in the public market following, the market price of our common stock may decrease. These sales might also make it more difficult for us to raise capital by selling equity or equity-related securities at a time and price that it otherwise would deem appropriate.

The market price of our common stock will continue to fluctuate and may decline if the benefits of the merger do not meet the expectations of financial analysts.

The market price of our common stock may fluctuate significantly following the merger, including if we do not achieve the perceived benefits of the merger as rapidly, or to the extent anticipated by, financial analysts or the effect of the merger on our financial results is not consistent with the expectations of financial analysts. If the price of our common stock decreases, our stockholders will lose some or all of the value of their investment in our common stock. In addition, the stock market has experienced significant price and volume fluctuations in recent times which, if they continue to occur, could have a material adverse effect on the market for, or liquidity of, our common stock, regardless of our actual operating performance.

In connection with the merger, we incorporated Energen’s hedging activities into our business. We will bear all of the economic impact of such hedges and may be exposed to additional commodity price risks arising from such hedges. Actual crude oil, natural gas and natural gas liquids prices may differ from the combined company’s expectations and, as a result, such hedges could have a negative impact on our business.

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

Market conditions for oil and natural gas, and particularly volatility in prices for oil and natural gas, have in the past adversely affected, and may in the future 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 five 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 $26.19 per barrel, or Bbl, in February 2016 to a high of $107.95 per Bbl in June 2014. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. During 2018, WTI prices ranged from $44.48 to $77.41 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On January 28, 2019, the WTI posted price for crude oil was $51.79 per Bbl and the Henry Hub spot market price of natural gas was $3.05 per MMBtu, representing decreases of 33% and 51%, respectively, from the high of $77.41 per Bbl of oil and $6.24 per MMBtu for natural gas during 2018. In response to recent declines in commodity prices, many producers have reduced their capital expenditure budgets. If the prices of oil and natural gas remain 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 in the past contributed, and may in the future contribute, to 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, may precipitate an economic slowdown. Concerns about global economic growth may have an 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, 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 2018, our total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $3.3 billion. Our 2019 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $2.7 billion to $3.0 billion, representing an increase of 85% over our 2018 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 2019 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. 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 $60.00 per Bbl WTI, we currently have approximately 11,868 gross (7,633 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage. As of December 31, 2018, only 416 of our gross identified potential horizontal 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 3,195 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. Through December 31, 2018, we are the operator of, have participated in, or have acquired a total of 1,465 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, 2018, we had leases representing 37,536 net acres expiring in 2019, 27,690 net acres expiring in 2020, 6,867 net acres expiring in 2021, 254 net acres expiring in 2022 and no net acres expiring in 2023. 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 2019, 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 fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options and may in the future enter into forward sale contracts or additional fixed price swap, fixed price basis swap derivatives or costless collars for a portion of our production. Although we have hedged a portion of our estimated 2018 and 2019 production, we may still be adversely affected by continuing and prolonged declines in the price of oil.

We use fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of our oil and natural gas 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 NYMEX WTI pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. Under the Company’s costless collar contracts, we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the call option price. The counterparty is required to make a payment to us if the settlement price for any settlement period is less than the put option price. 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, 2018, we had the following commodity contracts in place covering NYMEX WTI (Cushing and Magellan East Houston) crude oil, Brent crude oil and NYMEX Henry Hub and Waha Hub natural gas for the production period of January 2019 through December 2019:

- crude oil swap contracts priced at a weighted average price of $61.07 WTI Cushing for 10,638,000 aggregate Bbls;

- crude oil swap contracts priced at a weighted average price of $72.39 WTI Magellan East Houston for 1,270,000 aggregate Bbls;
- crude oil swap contracts priced at a weighted average price of $68.02 Brent for 2,005,000 aggregate Bbls;
- crude oil basis swap contracts priced at a weighted average price of $(5.56) for 17,012,000 aggregate Bbls for the spread between the WTI Midland price and the WTI Cushing price;
- natural gas swap contracts priced at a weighted average price of $3.06 Henry Hub for 25,550,000 aggregate MMBtu;

- natural gas basis swap contracts priced at a weighted average price of $(1.60) Waha Hub for 18,250,000 aggregate MMBtu;
- natural gas liquid swaps priced at a weighted average price of $27.30 Mont Belvieu for 2,760,000 aggregate Bbls;
- crude oil three-way collars contracts with a WTI Cushing short put price of $38.10, floor price of $48.10 and a ceiling price of $63.70 for 7,570,000 aggregate Bbls;
- crude oil three-way collars contracts with a WTI Magellan East Houston short put price of $56.82, floor price of $66.82 and a ceiling price of $77.60 for 994,000 aggregate Bbls; and
- crude oil three-way collars contracts with a Brent short put price of $55.00, floor price of $65.00 and a ceiling price of $82.47 for 2,000,000 aggregate Bbls.

We have crude oil basis swap contracts priced at a weighted average price of $(1.21) WTI for 15,120,000 aggregate Bbls with a production period of January 2020 through December 2020. To the extent that the prices of oil and natural gas remain at current levels or decline further, we will not be able to economically 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 long-term agreements with Trafigura, Shell Trading (US) Company and Vitol under which we are obligated to deliver specified quantities of oil to such companies. Our maximum delivery obligation under these agreements varies for different periods, ranging from 23,750 barrels of oil per day to up to a maximum of 50,000 barrels of oil per day. See "Business and Properties—Marketing and Customers" above. 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 $95.5 million at December 31, 2018) and receivables from purchasers of our oil and natural gas production (approximately $296.5 million at December 31, 2018). 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, 2018, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (26%); Koch Supply & Trading LP (15%) and Occidental Energy Marketing Inc (11%). For the year ended December 31, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (31%); Koch Supply & Trading LP (19%); and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2016, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (45%); Koch Supply & Trading LP (15%); and Enterprise Crude Oil LLC (13%). 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 $12.62, $11.11 and $11.23 for the years ended December 31, 2018, 2017 and 2016, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the years ended December 31, 2018, 2017 and 2016 was $594.8 million, $321.9 million and $176.4 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.

No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2018 and 2017. An impairment on proved oil and natural gas properties of $245.5 million was recorded for the years ended December 31, 2016. 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.

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, 2018, 2017 and 2016 (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, 2018, 2017 and 2016 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, 2018, 2017 and 2016, respectively, in accordance with the SEC guidelines applicable to reserve estimates for such periods.

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 35% of our total estimated proved reserves as of December 31, 2018, 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 currently 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, 2018, all of our proved reserves were attributable to the Wolfberry play in the Midland Basin. 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, 2018, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (26%); Koch Supply & Trading LP (15%) and Occidental Energy Marketing Inc (11%). For the year ended December 31, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (31%); Koch Supply & Trading LP (19%); and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2016, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (45%); Koch Supply & Trading LP (15%); and Enterprise Crude Oil LLC (13%). 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.

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

Our business operations have grown substantially since our initial public offering in October 2012 and we expect our business operations to continue to grow in the future. 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, which interconnects with third party pipelines. 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 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 imposed 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. Even if federal regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term, and at the state and local levels. 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, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection,” to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has 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.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural 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 rules seek 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. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. 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 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. 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.

Recently enacted U.S. tax legislation as well as future U.S. tax legislations may adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Ac, which we refer to as the Tax Act, that significantly reforms the Internal Revenue Code of 1986, as amended, which we refer to as the Code. Among other changes, the Tax Act (i) reduces the maximum U.S. corporate income tax rate from 35% to 21%, (ii) preserves long-standing upstream oil and gas tax provisions such as immediate deduction of intangible drilling, (iii) allows for immediate expensing of capital expenditures for tangible personal property for a period of time, (iv) modifies the provisions related to the limitations on deductions for executive compensation of publicly traded corporations and (v) enacts new limitations regarding the deductibility of interest expense. The Tax Act is complex and far-reaching, and while we have evaluated the resulting impact of its enactment on us and recorded adjustments as required in our financial statements, aspects of the Tax Act are unclear and may not be clarified for some time. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations and assumptions could have an adverse effect on our business, results of operations, financial condition and cash flow.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and gas industry, including (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. These proposed changes in the U.S. tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flows.

Regulation of greenhouse gas emissions 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.”
At the international level, in December 2015, the United States participated in 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 went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. 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, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, 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 or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such 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 hotter or 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.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, 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 or other oil and gas waste 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. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells, could have a material adverse effect on our business, financial condition and results of 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.

Rattler Midstream Operating LLC’s rates are subject to review by federal regulators, which could adversely affect our revenues.

Our subsidiary Rattler Midstream Operating LLC has a tariff on file with FERC to gather crude oil in interstate commerce. Pipelines that gather or transport crude oil for third parties in interstate commerce are, among other things, subject to regulation of the rates and terms and conditions of service by the FERC. Rattler is also subject to annual reporting requirements and may also be required to respond to requests for information from government agencies, including compliance audits conducted by FERC.

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 2018, 2017 and 2016, 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, 2018, 2017 and 2016 we incurred \$36.8 million, \$34.2 million and \$33.5 million, respectively, of stock based compensation expense, of which we capitalized \$10.0 million, \$8.6 million and \$7.1 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, 2018, we had total long-term debt of $4.5 billion, including $2.1 billion outstanding under our 4.750% Senior Notes due 2024, which we refer to as the 2024 Notes, our 5.375% Senior Notes due 2025, which we refer to as the 2025 Notes and an aggregate of $530.0 million of notes issued by Energen, which became our wholly owned subsidiary at the effective time of the merger, which notes remained outstanding following the closing of the merger and are collectively referred to as the Energen Notes, and we had an unused borrowing base availability of $0.5 billion under our revolving credit facility. As of December 31, 2018, Viper, one of our subsidiaries, had $411.0 million in outstanding borrowings, and $144.0 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 indentures 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 indentures governing our outstanding 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 Viper, the general partner and Viper's subsidiaries, Viper Energy Partners LLC and Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC), are designated as unrestricted subsidiaries under the indentures governing our outstanding 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 indentures governing our 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 indentures governing our 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 our 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 $2.65 billion, of which we have elected a commitment amount of $2.0 billion. The borrowing base is subject to scheduled annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. As of December 31, 2018, we had $1.5 billion borrowings outstanding under our revolving credit facility, of which approximately $559.0 million was used by us to repay in full all borrowings under Energen's credit facility outstanding immediately prior to the effective time of the merger. Our weighted average interest rate on borrowings under our revolving credit facility was 4.10% on December 31, 2018. We expect to borrow 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, to pay interest on or to refinance our indebtedness, including our 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 indentures governing our 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 indentures governing our senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2018, our borrowing base under our revolving credit facility was set at $2.65 billion, of which we have elected a commitment amount of $2.0 billion and we had $1.5 billion of outstanding borrowings under this facility, of which approximately $559.0 million was used by us to repay in full all borrowings under Energen’s credit facility outstanding immediately prior to the effective time of the merger. As of December 31, 2018, Viper had $411.0 million in outstanding borrowings, and $144.0 million available for borrowing, under its revolving credit facility. Further, the indentures governing the senior notes allow us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indentures governing the senior notes also allow 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 indentures governing the senior notes do 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 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. As of December 31, 2018, we had $1.5 billion borrowings outstanding under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 4.10% on December 31, 2018. Viper’s weighted average interest rate on borrowings from its revolving credit facility was 4.34% during the year ended December 31, 2018. As of December 31, 2018, Viper had $411.0 million in outstanding borrowings, and $144.0 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 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.

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.

In the past, we have engaged in transactions with affiliated companies and may do so again in the future. These transactions, 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.

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.

The declaration of dividends on our common stock is within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends in the future or at levels anticipated by our stockholders.

On February 13, 2018, we initiated payment of quarterly cash dividends on our common stock payable beginning with the first quarter of 2018. The decision to pay any future dividends, however, is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, or declare dividends at rates that are less than currently anticipated, either of which could reduce returns to our stockholders.

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

If we were to experience an "ownership change," as determined under Section 382 of the Code, our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

As of December 31, 2018, we had a net operating loss, or NOL, carry forward of approximately $567.8 million for federal income tax purposes, including $58.6 million acquired as part of the Energen acquisition. These acquired NOLs as well as $2.8 million in tax credits acquired from Energen are subject to an annual limitation under Section 382 of the Code.

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.

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. While the outcome of the pending litigation, disputes or claims cannot be predicted with certainty, in the opinion of our management, none of these matters, 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 Select Global Market under the symbol "FANG".

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

	High	Low	Cash Dividends per Share of Common Stock
2018			
1st Quarter	$134.60	$105.66	$ 0.125
2nd Quarter	$138.14	$107.78	$ 0.125
3rd Quarter	$138.25	$111.31	$ 0.125
4th Quarter(2)	$140.78	$85.19	$ 0.125
2017			
1st Quarter	$114.00	$96.05	$ —
2nd Quarter	$108.17	$83.22	$ —
3rd Quarter	$98.36	$82.77	$ —
4th Quarter	$127.45	$95.69	$ —

(1) The Q4 2018 distribution is payable on February 28, 2918 to unitholders of record at the close of business on February 21, 2019.

Holders of Record
There were 20 holders of record of our common stock on February 15, 2019.

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."

On February 13, 2018, we announced the initiation of an annual cash dividend in the amount of $0.50 per share of our common stock payable quarterly which began with the first quarter of 2018. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination.

Recent Sales of Unregistered Securities

On October 31, 2018, we issued approximately 2.6 million shares of our common stock to Ajax and certain other holders as part of the consideration for the Ajax acquisition. These shares were issued in reliance upon the exemption from the registration requirements of the Securities Act provided by Section 4(a)(2) of the Securities Act, as sales by an issuer not involving any public offering. In connection with the closing of the Ajax acquisition on October 31, 2018, we entered into a registration rights agreement with Ajax and certain other holders of our common stock pursuant to which we filed a shelf registration statement with the SEC to facilitate the resale of common stock issued in the Ajax acquisition. The shelf registration statement became automatically effective on November 30, 2018. Pursuant to this registration rights agreement, we also agreed to provide certain demand and piggyback registration rights to such holders.

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, 2018, 2017 and 2016 and the balance sheet data as of December 31, 2018 and 2017 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, 2015 and 2014 and the balance sheet data as of December 31, 2016, 2015 and 2014 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)	2018[(1)]	2017	2016	2015	2014
Statements of Operations Data:					
Total revenues	$2,176,256	$1,205,111	$527,107	$446,733	$495,718
Total costs and expenses	1,165,468	600,091	595,724	1,187,002	283,048
Income (loss) from operations	1,010,788	605,020	(68,617)	(740,269)	212,670
Other income (expense)	102,469	(107,831)	(96,099)	(8,831)	92,286
Income (loss) before income taxes	1,113,257	497,189	(164,716)	(749,100)	304,956
Provision for (benefit from) income taxes	168,362	(19,568)	192	(201,310)	108,985
Net income (loss)	944,895	516,757	(164,908)	(547,790)	195,971
Less: Net income attributable to non-controlling interest	99,223	34,496	126	2,838	2,216
Net income (loss) attributable to Diamondback Energy, Inc.	$845,672	$482,261	$(165,034)	$(550,628)	$193,755
Earnings per common share					
Basic	$8.09	$4.95	$(2.20)	$(8.74)	$3.67
Diluted	$8.06	$4.94	$(2.20)	$(8.74)	$3.64
Weighted average common shares outstanding					
Basic	104,622	97,458	75,077	63,019	52,826
Diluted	104,929	97,688	75,077	63,019	53,297
Cash dividends declared per common share	$0.500	$—	$—	$—	$—

(1) Our results of operations for 2018 include those of Energen and its subsidiaries acquired by us in the merger from the period of November 29, 2018, the closing date of the merger, through December 31, 2018.

	As of December 31,				
(In thousands)	2018	2017	2016	2015	2014
Balance Sheet Data:					
Cash and cash equivalents	$214,516	$112,446	$1,666,574	$20,115	$30,183
Net property and equipment	20,371,975	7,343,617	3,390,857	2,597,625	2,791,807
Total assets	21,595,687	7,770,985	5,349,680	2,750,719	3,095,481
Current liabilities	1,019,612	577,428	209,342	141,421	266,729
Long-term debt	4,464,338	1,477,347	1,105,912	487,807	673,500
Total stockholders’/ members’ equity[(1)]	13,699,287	5,254,860	3,697,462	1,875,972	1,751,011

Total equity	14,166,262	5,581,737	4,018,292	2,108,973	1,985,213

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	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Other Financial Data:					
Net cash provided by operating activities	$1,564,505	$888,625	$332,080	$416,501	$356,389
Net cash used in investing activities	(3,503,043)	(3,132,282)	(1,310,242)	(895,050)	(1,481,997)
Net cash provided by financing activities	2,040,608	689,529	2,624,621	468,481	1,140,236

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Consolidated Adjusted EBITDA(2)	$1,539,031	$928,039	$387,535	$449,245	$398,334

(1) For the years ended December 31, 2018, 2017, 2016, 2015 and 2014, total stockholders' equity excludes $467.0 million, $326.9 million, $320.8 million $233.0 million and $234.2 million, respectively, of non-controlling interest related to Viper Energy Partners LP.

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

Non-GAAP financial measure and reconciliation

Consolidated 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 Consolidated Adjusted EBITDA as net income (loss) plus non-cash (gain) loss on derivative instruments, net, 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, loss on revaluation of investment, loss on extinguishment of debt, merger and integration expense, income tax (benefit) provision and non-controlling interest in net (income) loss. Consolidated Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. Management believes Consolidated 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 Consolidated 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. Consolidated 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 Consolidated 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 Consolidated Adjusted EBITDA. Our computations of Consolidated 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 Consolidated Adjusted EBITDA to the GAAP financial measure of net income (loss):

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Net income (loss)	$944,895	$516,757	$(164,908)	$(547,790)	$195,971
Non-cash loss (gain) on derivative instruments, net	(221,732)	84,240	26,522	112,918	(117,109)
Interest expense, net	87,276	40,554	40,684	41,510	34,515
Depreciation, depletion and amortization	623,039	326,759	178,015	217,697	170,005
Impairment of oil and natural gas properties	—	—	245,536	814,798	—
Non-cash equity-based compensation expense	36,798	34,178	33,532	24,572	14,253
Capitalized equity-based compensation expense	(10,034)	(8,641)	(7,079)	(6,043)	(4,437)
Asset retirement obligation accretion expense	2,132	1,391	1,064	833	467
Loss on revaluation of investment	550	—	—	—	—
Loss on extinguishment of debt	—	—	33,134	—	—
Merger and integration expense	36,831	—	—	—	—
Income tax (benefit) provision	168,362	(19,568)	192	(201,310)	108,985
Non-controlling interest in net (income) loss	(129,086)	(47,631)	843	(7,940)	(4,316)
Consolidated Adjusted EBITDA	$1,539,031	$928,039	$387,535	$449,245	$398,334

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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 horizontal development of the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Spring formations in the Delaware Basin. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production.

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

	Year Ended December 31,		
	2018	2017	2016
Oil (MBbls)	72 %	74 %	73 %
Natural gas (MMcf)	12 %	12 %	11 %
Natural gas liquids (MBbls)	16 %	14 %	16 %
	100%	100%	100%

On December 31, 2018, our acreage position in the Permian Basin was approximately 604,367 gross (461,218 net) acres, which consisted primarily of approximately 231,100 gross (194,661 net) acres in the Midland Basin and approximately 232,143 gross (170,205 net) acres in the Delaware Basin.

2018 was another transformational year for us. We successfully closed three acquisitions in the fourth quarter of 2018, including our acquisition of Energen Corporation, or Energen, which acquisitions, on a combined basis, almost doubled our core acreage position. During the same period, oil prices declined dramatically, and we quickly addressed the issue by announcing a reduction in activity levels in late 2018 and acting on that plan immediately in 2019. At current commodity prices, we expect to grow production by over 27% year over year within cash flow in 2019, while increasing our dividend by 50% beginning with the first quarter of 2019. By remaining focused on corporate returns and prudent capital allocation, we believe that in the current commodity price environment we are positioned to generate significant free cash flow while continuing to grow production at industry leading rates in 2020 and beyond. We are operating 21 rigs now and currently intend to operate between 18 and 22 rigs in 2019. 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.

2018 Transactions and Recent Developments

Merger with Energen Corporation

On November 29, 2018, we completed our acquisition of Energen in an all-stock transaction, which we refer to as the merger. We consolidate our results of operations with those of Energen and its subsidiaries acquired by us in the merger beginning with November 29, 2019, the closing date of the merger. We accounted for the merger as a business combination.

The addition of Energen’s assets increased our assets to: (i) over 273,000 net Tier One acres in the Permian Basin, an increase of 57% from third quarter 2018 Tier One acreage of approximately 174,000 net acres, (ii) over 7,200 estimated total net horizontal Permian locations, an increase of over 120% from third quarter 2018 estimated net locations, and (iii) approximately 394,000 net acres across the Midland and Delaware Basins, an increase of 82% from our approximately 216,000 net acres as September 30, 2018, in each after giving effect to our recently completed Ajax acquisition and ExL acquisition discussed below.

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Under the terms of the merger agreement, we assumed Energen's outstanding debt, which at the effective time of the merger was approximately $1.1 billion. This amount consisted of $559.0 million of borrowings under Energen's existing credit facility, $400.0 million aggregate principal amount of 4.625% Notes, due September 1, 2021, $20.0 million aggregate principal amount of 7.32% Medium-term Notes, Series A, due July 28, 2022, $10.0 million aggregate principal amount of 7.35% Medium-term Notes, Series A, due July 28, 2027, and $100.0 million aggregate principal amount of 7.125% Medium-term Notes, Series B, due February 15, 2028, which we collectively refer to as the Energen Notes. In connection with the closing of the Merger, we repaid the outstanding borrowings of $559.0 million under the Energen credit facility using cash on hand and borrowings under our revolving credit facility.

Ajax Resources, LLC

On October 31, 2018, we acquired certain leasehold interests and related assets of Ajax Resources, LLC, which we refer to as Ajax, which included approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900.0 million in cash, subject to certain adjustments, and approximately 2.6 million shares of our common stock, which we refer to as the Ajax acquisition. The Ajax acquisition was effective as of July 1, 2018. The cash portion of this transaction was funded through a combination of cash on hand, proceeds from the sale of mineral interests to Viper Energy Partners LP, which we refer to as Viper or the Partnership, described below, borrowings under our revolving credit facility and proceeds from our September 2018 senior note offering. See "—New Senior Notes" below.

In connection with the closing of the Ajax acquisition on October 31, 2018, we entered into a registration rights agreement with Ajax and certain other holders of our common stock pursuant to which we filed a shelf registration statement with the SEC to facilitate the resale of common stock issued in the Ajax acquisition. The shelf registration statement became automatically effective on November 30, 2018. Pursuant to this registration rights agreement, we also agreed to provide certain demand and piggyback registration rights to such holders.

On December 11, 2018, we entered into an ATM Equity Offering SM Sales Agreement with Ajax, certain other holders of our common stock and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as sales agent, in connection with potential sales from time to time during the term of the sales agreement by Ajax of up to approximately 2.0 million shares of our common stock under the above-referenced shelf registration statement.

ExL Petroleum Management, LLC and EnergyQuest II LLC Acquisition

On October 31, 2018, we acquired certain leasehold interests and related assets of ExL Petroleum Management, LLC, ExL Petroleum Operating, Inc. and EnergyQuest II LLC, which included an aggregate of approximately 3,646 net leasehold acres in the Northern Midland Basin for a total of $312.5 million in cash, subject to certain adjustments. These acquisitions which we collectively refer to as the ExL acquisition, were effective as of August 1, 2018, and were funded through a combination of cash on hand, proceeds from the sale of assets to the Partnership (described below) and borrowing under our revolving credit facility.

Drop-down Transaction

On August 15, 2018, we sold to the Partnership mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by us, for $175.0 million, which we refer to as the Drop-down Transaction.

Alliance with Obsidian Resources, L.L.C.

We entered into a participation and development agreement, which we refer to as the DrillCo agreement, dated September 10, 2018, with Obsidian Resources, L.L.C., which we refer to as CEMOF, to fund oil and natural gas development. Funds managed by CEMOF and its affiliates have agreed to commit to funding certain costs out of CEMOF's net production revenue and, for a period of time, to the extent not funded by such revenue, up to an additional $300.0 million, to fund drilling programs on locations provided by us. Subject to adjustments depending on asset characteristics and return expectations of the selected drilling plan, CEMOF will fund up to 85% of the costs associated with new wells drilled under the DrillCo agreement and is expected to receive an 80% working interest in these wells until it reaches certain payout thresholds equal to a cumulative 9% and then 13% internal rate of return. Upon reaching the final internal rate of return target, CEMOF's interest will be reduced to 15%, while our interest will increase to 85%.

Transportation Contracts

In 2018, we entered into 100,000 BOD/d volume commitments with each of the EPIC Pipeline project and the Gray Oak Pipeline project, with 50% of the volumes covered via take or pay contracts and 50% covered via acreage dedications. In connection with such commitments, in February 2019 we closed on our acquisition of 10% equity interests in each of the EPIC and the Gray Oak Pipeline projects. The EPIC and Gray Oak Pipeline projects are each anticipated to be operational in the second half of 2019. These long-haul crude oil pipelines, which will terminate in the refinery-dense, export-focused Texas Gulf Coast market, will allow us to access premium Texas Gulf Coast pricing as opposed to discounted local pricing at Midland, Texas.

New Senior Notes

On January 29, 2018, we issued $300.0 million aggregate principal amount of new 2025 notes as additional notes under our existing indenture, dated as of December 20, 2016, as supplemented, among us, subsidiary guarantors party thereto and Wells Fargo, as trustee, under which we previously issued $500.0 million aggregate principal amount of our existing 5.375% Senior Notes due 2025. We received approximately $308.4 million in net proceeds, after deducting the initial purchaser's discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2025 notes. We used the net proceeds from the issuance of the new 2025 notes to repay a portion of the outstanding borrowings under our revolving credit facility.

On September 25, 2018, we issued $750.0 million aggregate principal amount of new 4.750% senior notes due 2024, or the new 2024 notes. The new 2024 notes were issued in a transaction exempt from the registration requirements under the Securities Act. We received approximately $740.7 million in net proceeds, after deducting the initial purchasers' discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2024 notes. We used a portion of the net proceeds from the issuance of the new 2024 notes to repay a portion of the outstanding borrowings our revolving credit facility and we used the balance for general corporate purposes, including the funding of a portion of the cash consideration for the Ajax acquisition.

Recapitalization, Tax Status Election and Related Transactions by Viper

In March 2018, Viper announced that the Board of Directors of its general partner had unanimously approved a change of Viper's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election. In connection with making this election, on May 9, 2018 Viper (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, or the Operating Company, (iii) amended and restated its existing registration rights agreement with us and (iv) entered into an exchange agreement with us, Viper's general partner, or the General Partner, and the Operating Company. Simultaneously with the effectiveness of these agreements, we delivered and assigned to Viper the 73,150,000 common units we owned in exchange for (i) 73,150,000 of Viper's newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018, or the Recapitalization Agreement. Immediately following that exchange, Viper continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and we owned the remaining approximately 64% of the outstanding units issued by the Operating Company. Upon completion of Viper's July 2018 offering of units, Viper owned approximately 41% of the outstanding units issued by the Operating Company and we owned the remaining approximately 59%. The Operating Company units and Viper's Class B units owned by us are exchangeable from time to time for Viper's common units (that is, one Operating Company unit and one Viper Class B unit, together, will be exchangeable for one Viper common unit).

On May 10, 2018, the change in Viper's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to Viper in respect of its general partner interest and (ii) we made a cash capital contribution of $1.0 million to Viper in respect of the Class B units. We, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, we also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of Viper and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as Viper’s general partner and we continue to control Viper. After the effectiveness of the tax status election and the completion of related transactions, Viper’s minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to Viper’s business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding

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the tax status election and related transactions, please refer to Viper's Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and Viper's Current Report on Form 8-K filed with the SEC on May 15, 2018.

Viper's July 2018 Equity Offering

In July 2018, Viper completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, we owned approximately 59% of Viper's total units then outstanding. Viper received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and estimated offering expenses. Viper used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under its revolving credit facility.

Operational Update

We are operating 21 rigs now and currently intend to operate between 18 and 22 drilling rigs in 2019 across our asset base in the Midland and Delaware Basins.

In the Midland Basin, we continue have positive results across our core development areas located within Midland, Martin, Howard, Glasscock and Andrews counties, where development has primarily focused on drilling long-lateral, multi-well pads targeting the Spraberry and Wolfcamp formations.

In the Delaware Basin, we have now drilled and completed multiple wells in Pecos, Reeves and Ward counties targeting the Wolfcamp A, which we believe has been de-risked across a significant portion of our total acreage position and remains our primary development target. In 2019, we expect to focus development on these areas as well as our Northern Delaware Basin acreage acquired in the Energen transaction.

We continue to focus on low cost operations and best in class execution. To combat rising service costs, we have looked to lock in pricing for dedicated activity levels and will continue to seek opportunities to control additional well cost where possible. Our 2019 drilling and completion budget accounts for capital costs that we believe will cover potential increases in our service costs during the year.

2019 Capital Budget

We have currently budgeted a 2019 total capital spend of $2.7 billion to $3.0 billion, consisting of $2.3 billion to $2.55 billion for horizontal drilling and completions including non-operated activity, $400.0 million to $450.0 million for midstream and infrastructure investments, excluding equity investments in long-haul pipelines or the cost of any leasehold and mineral rights acquisitions. We expect to drill and complete 290 to 320 gross horizontal wells in 2019.

Operating Results Overview

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

	Year Ended December 31,		
	2018	2017	2016
Oil (Bbls)/d	94,156	58,678	31,590
Natural gas (Mcf)/d	94,983	56,602	29,313
Natural gas liquids (Bbls)/d	20,453	11,112	6,556

Total average production per day	130,439	79,224	43,031

Our average daily production for the year ended December 31, 2018 as compared to the year ended December 31, 2017 increased by 51,215 BOE/d, or 65%.

During the year ended December 31, 2018, we drilled 189 gross (168 net) horizontal wells and completed 176 gross (155 net) operated horizontal wells.

Reserves and pricing

Ryder Scott prepared estimates of our proved reserves at December 31, 2018, 2017 and 2016 (which include estimated proved reserves attributable to Viper). The prices used to estimate proved reserves for all periods did not give effect to derivative

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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.

	2018	2017	2016
Estimated Net Proved Reserves:			
Oil (MBbls)	626,936	233,181	139,174
Natural gas (MMcf)	1,048,649	285,369	174,896
Natural gas liquids (MBbls)	190,291	54,609	37,134
Total (MBOE)	992,001	335,352	205,458

	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
	2018	2017	2016
Oil (per Bbl)	$59.63	$48.03	$39.94
Natural gas (per Mcf)	$1.47	$2.06	$1.36
Natural gas liquids (per Bbl)	$24.43	$20.79	$12.91

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

The following table presents the sources of our revenues for the years presented:

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Oil sales	88 %	88 %	89 %
Natural gas sales	3 %	4 %	4 %
Natural gas liquid sales	9 %	8 %	7 %
	100%	100%	100%

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2018, WTI posted prices ranged from $44.48 to $77.41 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On December 28, 2018, the WTI posted price for crude oil was $45.15 per Bbl and the Henry Hub spot market price of natural gas was $3.25 per MMBtu. 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 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 expenses. 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.

Midstream services expense. These are costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, depletion and amortization. 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 of oil and natural gas properties. This is the cost to reduce proved oil and gas properties to the calculated full cost ceiling value.

Other income (expense)

Interest income (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. This amount reflects interest paid to our lender plus the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees net of interest received on our cash and cash equivalents.

Gain (loss) on derivative instruments, net. 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.

Deferred tax assets (liabilities). 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. Our results of operations for 2018 include those of Energen and its subsidiaries acquired by us in the merger for the period November 29, 2018, the closing date of the merger, through December 31, 2018.

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Revenues:			
Oil, natural gas and natural gas liquids	$2,129,780	$1,186,275	$527,107
Lease bonus	2,920	11,764	—
Midstream services	34,254	7,072	—
Other operating income	9,302	—	—
Total revenues	2,176,256	1,205,111	527,107
Operating expenses:			
Lease operating expenses	204,975	126,524	82,428
Production and ad valorem taxes	132,661	73,505	34,456
Gathering and transportation	26,113	12,834	11,606
Midstream services	71,878	10,409	—
Depreciation, depletion and amortization	623,039	326,759	178,015
Impairment of oil and natural gas properties	—	—	245,536
General and administrative expenses	64,554	48,669	42,619
Asset retirement obligation accretion	2,132	1,391	1,064
Merger & integration expense	36,831	—	—
Other operating expense	3,285	—	—
Total expenses	1,165,468	600,091	595,724
Income (loss) from operations	1,010,788	605,020	(68,617)
Interest expense, net	(87,276)	(40,554)	(40,684)
Other income, net	88,996	10,235	3,064
Gain (loss) on derivative instruments, net	101,299	(77,512)	(25,345)
Loss on revaluation of investment	(550)	—	—
Loss on extinguishment of debt	—	—	(33,134)
Total other income (expense), net	102,469	(107,831)	(96,099)
Income (loss) before income taxes	1,113,257	497,189	(164,716)
Provision for (benefit from) income taxes	168,362	(19,568)	192
Net income (loss)	944,895	516,757	(164,908)
Net income attributable to non-controlling interest	99,223	34,496	126
Net income (loss) attributable to Diamondback Energy, Inc.	$845,672	$482,261	$(165,034)

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	Year Ended December 31,		
	2018	2017	2016
Production Data:			
Oil (MBbls)	34,367	21,418	11,562
Natural gas (MMcf)	34,669	20,660	10,728
Natural gas liquids (MBbls)	7,465	4,056	2,399
Combined volumes (MBOE)	47,610	28,917	15,749
Daily combined volumes (BOE/d)	130,439	79,224	43,031
Average Prices:			
Oil (per Bbl)	$54.66	$48.75	$40.70
Natural gas (per Mcf)	1.76	2.53	2.10
Natural gas liquids (per Bbl)	25.47	22.20	14.20
Combined (per BOE)	44.73	41.02	33.47
Oil, hedged ($ per Bbl)(1)	51.20	48.94	40.80
Natural gas, hedged ($ per MMbtu)(1)	1.72	2.65	2.06
Natural gas liquids, hedged ($ per Bbl)(1)	25.46	—	—
Average price, hedged ($ per BOE)(1)	42.20	41.26	33.54
Average Costs per BOE:			
Lease operating expense	$4.31	$4.38	$5.23
Production and ad valorem taxes	2.79	2.54	2.19
Gathering and transportation expense	0.55	0.44	0.74
General and administrative - cash component	0.79	0.80	1.03
Total operating expense - cash	$8.44	$8.16	$9.19
General and administrative - non-cash component	$0.57	$0.88	$1.68
Depreciation, depletion and amortization	13.09	11.30	11.30
Interest expense, net	1.83	1.40	2.58
Merger and integration expense	0.77	—	—
Total expenses	$16.26	$13.58	$15.56
Average realized oil price ($/Bbl)	$54.66	$48.75	$40.70
Average NYMEX ($/Bbl)	$65.23	$50.80	$43.29
Differential to NYMEX	$(10.57)	$(2.05)	$(2.59)
Average realized oil price to NYMEX	84 %	96 %	94 %
Average realized natural gas price ($/Mcf)	$1.76	$2.53	$2.10
Average NYMEX ($/Mcf)	$3.17	$2.99	$2.52
Differential to NYMEX	$(1.41)	$(0.46)	$(0.42)
Average realized natural gas price to NYMEX	56 %	85 %	83 %
Average realized natural gas liquids price ($/Bbl)	$25.47	$22.20	$14.20
Average NYMEX oil price ($/Bbl)	$65.23	$50.80	$43.29
Average realized natural gas liquids price to NYMEX oil price	39 %	44 %	33 %

(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.

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Comparison of the Years Ended December 31, 2018 and 2017

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $943.5 million, or 80%, to $2.2 billion for the year ended December 31, 2018 from $1.2 billion for the year ended December 31, 2017. 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 51,215 BOE/d to 130,439 BOE/d during the year ended December 31, 2018 from 79,224 BOE/d during the year ended December 31, 2017. The total increase in revenue of approximately $943.5 million is attributable to higher oil, natural gas liquids and natural gas production volumes and higher average sales prices for the year ended December 31, 2018 as compared to the year ended December 31, 2017. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 12,949 MBbls of oil, 14,009 MMcf of natural gas and 3,409 MBbls of natural gas liquids for the year ended December 31, 2018 as compared to the year ended December 31, 2017.

The net dollar effect of the increases in prices of approximately $201.2 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 $742.3 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 5.92	34,367	$ 203,383
Natural gas	$ (0.77)	34,669	$ (26,567)
Natural gas liquids	$ 3.26	7,465	$ 24,362
Total revenues due to change in price			$ 201,178

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	12,949	$ 48.75	$ 631,225
Natural gas	14,009	$ 2.53	$ 35,403
Natural gas liquids	3,409	$ 22.20	$ 75,699
Total change in revenues			$ 742,327
			$ 943,505

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

Lease Bonus Revenue. Lease bonus revenue was $2.9 million for the year ended December 31, 2018, $0.9 million of which was attributable to lease bonus payments to extend the term of two leases, reflecting an average bonus of $5,939 per acre and the remaining $2.0 million was attributable to lease bonus payments on five new leases, reflecting an average bonus of $11,649 per acre. Lease bonus revenue was $11.8 million for the year ended December 31, 2017, $2.8 million of which was attributable to lease bonus payments to extend the term of seven leases, reflecting an average bonus of $3,442 per acre and the remaining $9.1 million was attributable to lease bonus payments on three new leases, reflecting an average bonus of $14,320 per acre.

Midstream Services Revenue. Midstream services revenue was $34.3 million for the year ended December 31, 2018, an increase of $27.2 million as compared to $7.1 million for the year ended December 31, 2017. Our midstream services revenue represents fees charged to our joint interest owners and third parties for the transportation of oil and natural gas along with water gathering and related disposal facilities. These assets complement our operations in areas where we have significant production.

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Lease Operating Expenses. Lease operating expenses were $205.0 million ($4.31 per BOE) for the year ended December 31, 2018, an increase of $78.5 million from $126.5 million ($4.38 per BOE) for the year ended December 31, 2017. The increase in lease operating expense was a result of an increase in our producing well count. The decrease in lease operating expense per BOE was a result of lease operating expenses increasing at a lower percentage than the increase in production volumes.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $132.7 million for the year ended December 31, 2018, an increase of $59.2 million, or 80%, from $73.5 million for the year ended December 31, 2017. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, among other factors, whereas production taxes are based upon current year commodity prices. During the year ended December 31, 2018, production and ad valorem taxes per BOE increased by $0.25 as compared to the year ended December 31, 2017, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $71.9 million for the year ended December 31, 2018, an increase of $61.5 million as compared to $10.4 million for the year ended December 31, 2017. The increase was primarily due to additional build out of systems and increased throughput related to increased production. Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $296.3 million, or 91%, from $326.8 million for the year ended December 31, 2017 to $623.0 million for the year ended December 31, 2018.

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

	Year Ended December 31,	
	2018	2017
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$594,750	$321,870
Depreciation of midstream assets	18,803	3,451
Depreciation of other property and equipment	9,486	1,438
Depreciation, depletion and amortization expense	$623,039	$326,759
Oil and natural gas properties depreciation, depletion and amortization expense per BOE	$12.62	$11.11

The increase in depletion of proved oil and natural gas properties of $272.9 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017 resulted primarily from higher production levels and an increase in net book value on new reserves added.

General and Administrative Expenses. General and administrative expenses increased $15.9 million from $48.7 million for the year ended December 31, 2017 to $64.6 million for the year ended December 31, 2018. The increase was primarily due to an increase in employee count, including as a result of our recent merger with Energen.

Net Interest Expense. Net interest expense for the year ended December 31, 2018 was $87.3 million as compared to $40.6 million for the year ended December 31, 2017, an increase of $46.7 million. This increase was due primarily to a higher interest rate and increased average borrowings during the year ended December 31, 2018 as compared to the year ended December 31, 2017.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the year ended December 31, 2018, we had a cash loss on settlement of derivative instruments of $120.4 million as compared to a cash gain on settlement of derivative instruments of $6.7 million for the year ended December 31, 2017. For the year ended December 31, 2018, we had a positive change in the fair value of open derivative instruments of $221.7 million as compared to a negative change of $84.2 million for the year ended December 31, 2017. Our net gain on derivative instruments for the year ended December 31, 2018 was due to the assumption of Energen’s hedges and lower commodity prices.

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Provision for (Benefit from) Income Taxes. We recorded an income tax provision of $168.4 million for the year ended December 31, 2018 as compared to an income tax benefit of $19.6 million for the year ended December 31, 2017. Our effective tax rate was 15.1% for the year ended December 31, 2018 as compared to (3.9)% for the year ended December 31, 2017. The change in our income tax provision for the year ended December 31, 2018 as compared to the year ended December 31, 2017 is primarily due to the to the increase in pre-tax book income for the year ended December 31, 2018, partially offset by the tax effect reflected in the consolidated tax provision of the tax status change for Viper in the year ended December 31, 2018, the deferred tax benefits resulting from the change in the valuation allowance for the year ended December 31, 2017, and the reduction of the federal statutory tax rate enacted during the year ended December 31, 2017.

Comparison of the Years Ended December 31, 2017 and 2016

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $659.2 million, or 125%, to $1.2 billion for the year ended December 31, 2017 from $527.1 million for the year ended December 31, 2016. 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 36,193 BOE/d to 79,224 BOE/d during the year ended December 31, 2017 from 43,031 BOE/d during the year ended December 31, 2016. The total increase in revenue of approximately $659.2 million is attributable to higher oil, natural gas liquids and natural gas production volumes and higher average sales prices for the year ended December 31, 2017 as compared to the year ended December 31, 2016. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 9,856 MBbls of oil, 1,656 MBbls of natural gas liquids and 9,931 MMcf of natural gas for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

The net dollar effect of the increases in prices of approximately $213.7 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 $445.4 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes[1]	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 8.05	21,418	$ 172,403
Natural gas	$ 0.43	20,660	$ 8,884
Natural gas liquids	$ 8.00	4,056	$ 32,446
Total revenues due to change in price			$ 213,733

	Change in production volumes[1]	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			

Oil	9,856	$ 40.70	$ 401,080
Natural gas	9,931	$ 2.10	$ 20,834
Natural gas liquids	1,656	$ 14.20	$ 23,521
Total revenues due to change in production volumes			$ 445,435
Total change in revenues			$ 659,168

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

Lease Bonus Revenue. Lease bonus revenue was $11.8 million for the year ended December 31, 2017, $2.8 million of which was attributable to lease bonus payments to extend the term of seven leases, reflecting an average bonus of $3,442 per acre and the remaining $9.1 million was attributable to lease bonus payments on three new leases, reflecting an average bonus of $14,320 per acre. We had no lease bonus revenue for the year ended December 31, 2016.

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Midstream Services Revenue. Midstream services revenue was $7.1 million for the year ended December 31, 2017. We began generating midstream services revenue during the first quarter of 2017 and, prior to that period, had no midstream services revenue. Our midstream services revenue represents fees charged to our joint interest owners and third parties for the transportation of oil and natural gas along with water gathering and related disposal facilities. These assets complement our operations in areas where we have significant production.

Lease Operating Expenses. Lease operating expenses were $126.5 million ($4.38 per BOE) for the year ended December 31, 2017, an increase of $44.1 million from $82.4 million ($5.23 per BOE) for the year ended December 31, 2016. The increase in lease operating expense was due to an increase of 234 producing wells compared to 2016. This increase was offset by higher production volumes which resulted in a decrease in lease operating expense per BOE.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased to $73.5 million for the year ended December 31, 2017 from $34.5 million for the year ended December 31, 2016. 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. The increase in production and ad valorem taxes during the year ended December 31, 2017 as compared to 2016 was primarily due to an increase in our production taxes as a result of increased commodity prices and volumes.

Midstream Services Expense. Midstream services expense was $10.4 million for the year ended December 31, 2017. Prior to the first quarter of 2017, we had no midstream services expense. Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $148.7 million, or 84%, from $178.0 million for the year ended December 31, 2016 to $326.8 million for the year ended December 31, 2017.

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

	Year Ended December 31,	
	2017	2016
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$321,870	$176,369
Depreciation of midstream assets	3,451	252
Depreciation of other property and equipment	1,438	1,394
Depreciation, depletion and amortization expense	$326,759	$178,015
Oil and natural gas properties depreciation, depletion and amortization expense per BOE	$11.11	$11.23

The increase in depletion of proved oil and natural gas properties of $145.5 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016 resulted primarily from higher production levels and an increase in net book value on new reserves added.

Impairment of Oil and Natural Gas Properties. During the year ended December 31, 2016, we recorded an impairment of oil and gas properties of $245.5 million as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves. We did not record an impairment of oil and natural gas properties during the year ended December 31, 2017.

General and Administrative Expenses. General and administrative expenses increased $6.1 million from $42.6 million for the year ended December 31, 2016 to $48.7 million for the year ended December 31, 2017. The increase was due to an increase in salaries and benefits expense as a result of an increase in workforce.

Net Interest Expense. Net interest expense for the year ended December 31, 2017 was $40.6 million as compared to $40.7 million for the year ended December 31, 2016, a decrease of $0.1 million. This decrease was due primarily to the issuance in October 2016 of new senior notes due 2024 with a lower interest rate than the senior notes which we redeemed in the fourth quarter of 2016 partially offset by the interest on the additional senior notes due in 2025 that we issued in December 2016.

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Gain (Loss) on Derivative Instruments, Net. 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, 2017 and 2016, we had a cash gain on settlement of derivative instruments of $6.7 million and $1.2 million, respectively. For the year ended December 31, 2017 and 2016, we had a negative change in the fair value of open derivative instruments of $84.2 million and $26.5 million, respectively.

Provision for (Benefit from) Income Taxes. We recorded an income tax benefit of $19.6 million for the year ended December 31, 2017 as compared to an income tax provision of $0.2 million for the year ended December 31, 2016. Our effective tax rate was (3.9)% for the year ended December 31, 2017 as compared to (0.1)% for the year ended December 31, 2016. The change in our income tax provision for the year ended December 31, 2017 as compared to the year ended December 31, 2016 is primarily due to the reduction in our valuation allowance against deferred tax assets, as well as the favorable impact of the reduction in the federal statutory tax rate enacted in December 2017. While we generated positive pre-tax income from continuing operations in 2017, our 2017 effective tax rate was negative due to the income tax benefit generated by these items.

Liquidity and Capital Resources

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

Liquidity and Cash Flow

Our cash flows for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net cash provided by operating activities	$1,564,505	$888,625	$332,080
Net cash used in investing activities	(3,503,043)	(3,132,282)	(1,310,242)
Net cash provided by financing activities	2,040,608	689,529	2,624,621
Net change in cash	$102,070	$(1,554,128)	$1,646,459

Operating Activities

Net cash provided by operating activities was $1.6 billion for the year ended December 31, 2018 as compared to $888.6 million for the year ended December 31, 2017. The increase in operating cash flows is primarily the result of an increase in our oil and natural gas revenues due to an increase in average prices and production growth during the year ended December 31, 2018.

Net cash provided by operating activities was $888.6 million for the year ended December 31, 2017 as compared to $332.1 million for the year ended December 31, 2016. The increase in operating cash flows is primarily the result of an increase in our oil and natural gas revenues due to an increase in average prices and production growth during the year ended December 31, 2017.

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.

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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 $3.5 billion, $3.1 billion and $1.3 billion during the years ended December 31, 2018, 2017 and 2016, respectively.

During the year ended December 31, 2018, we spent (a) $1.5 billion on capital expenditures in conjunction with our drilling program, in which we drilled 189 gross (168 net) horizontal wells and completed 176 gross (155 net) operated horizontal wells, (b) $204.2 million on additions to midstream assets, (c) $440.3 million for the acquisition of mineral interests, (d) $1.4 billion on leasehold acquisitions, (e) $6.8 million for the purchase of other property and equipment and (f) $110.7 million on investment in real estate.

During the year ended December 31, 2017, we spent (a) $792.6 million on capital expenditures in conjunction with our drilling program, in which we drilled 150 gross (130 net) horizontal wells and participated in the drilling of 16 gross (two net) non-operated wells, (b) $68.1 million on additions to midstream assets, (c) $407.5 million for the acquisition of mineral interests, (d) $1,960.6 million on leasehold acquisitions, (e) $50.3 million for the acquisition of midstream assets and (f) $22.8 million for the purchase of other property and equipment.

During the year ended December 31, 2016, we spent (a) $364.3 million on capital expenditures in conjunction with our drilling program, in which we drilled 73 gross (61 net) horizontal wells and two gross (one net) vertical wells and participated in the drilling of 19 gross (five net) non-operated wells, (b) $611.3 million on leasehold acquisitions, (c) $205.7 million on royalty interest acquisitions, (d) $9.9 million for the purchase of other property and equipment and (e) $121.4 million was placed in escrow as a deposit under the purchase agreement for oil and natural gas assets located in Pecos and Reeves counties in Texas.

Our investing activities for the years ended December 31, 2018, 2017 and 2016 are summarized in the following table:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Drilling, completion and infrastructure	$(1,460,509)	$(792,599)	$(363,087)
Additions to midstream assets	(204,222)	(68,139)	(1,188)
Acquisition of leasehold interests	(1,370,951)	(1,960,591)	(611,280)
Acquisition of mineral interests	(440,303)	(407,450)	(205,721)
Acquisition of midstream assets	—	(50,279)	—
Purchase of other property, equipment and land	(6,840)	(22,779)	(9,891)
Investment in real estate	(110,685)	—	—
Proceeds from sale of assets	80,098	65,656	4,661
Funds held in escrow	10,989	104,087	(121,391)
Equity investments	(612)	(188)	(2,345)
Purchase of other investments	(8)	—	—
Net cash used in investing activities	$(3,503,043)	$(3,132,282)	$(1,310,242)

Financing Activities

Net cash provided by financing activities for the years ended December 31, 2018, 2017 and 2016 was $2.0 billion, $689.5 million and $2.6 billion, respectively.

During the year ended December 31, 2018, the amount provided by financing activities was primarily attributable to the issuance of $1.1 billion of new senior notes, $1.4 billion of borrowings, net of repayments under our credit facility,

$559.0 million of repayments under Energen’s credit facility and an aggregate of $305.8 million of net proceeds from Viper’s public offerings, partially offset by $98.3 million of distributions to non-controlling interest and $37.3 million of dividends to stockholders.

During the year ended December 31, 2017, the amount provided by financing activities was primarily attributable to proceeds from Viper’s January and July 2017 equity offerings of $370.3 million as well as borrowings net of repayments of $370.0 million, partially offset by distributions to non-controlling interests of $41.4 million.

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During the year ended December 31, 2016, the amount provided by financing activities was primarily attributable to the aggregate proceeds of $2.1 billion from our January, July and December 2016 equity offerings partially offset by repayments of net borrowings of $75.0 million under our credit facility.

2024 Senior Notes

On October 28, 2016, we issued $500.0 million in aggregate principal amount of 4.750% senior notes due 2024, which we refer to as the existing 2024 notes, under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, which we refer to as the 2024 indenture. On September 25, 2018, we issued $750.0 million aggregate principal amount of new 4.750% senior notes due 2024, which we refer to as the new 2024 notes and, together with the existing 2024 notes, as the 2024 senior notes, as additional notes under, and subject to the terms of, the 2024 Indenture. We received approximately $740.7 million in net proceeds, after deducting the initial purchasers' discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2024 notes. We used a portion of the net proceeds from the issuance of the new 2024 notes to repay a portion of the outstanding borrowings our revolving credit facility and the balance for general corporate purposes, including funding a portion of the cash consideration for the Ajax acquisition.

The 2024 senior notes bear interest at a rate of 4.750% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017, and will mature on November 1, 2024. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2024 senior notes; provided, however, that the 2024 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream Operating LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.

For additional information regarding the 2024 senior notes, see Note 9—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

2025 Senior Notes

On December 20, 2016, we issued $500.0 million in aggregate principal amount of 5.375% senior notes due 2025, which we refer to as the exiting 2025 notes, under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, which we refer to as the 2025 indenture. On January 29, 2018, we issued $300.0 million aggregate principal amount of new 5.375% senior notes due 2025, which we refer to as the new 2025 notes and, together with the existing 2025 notes, as additional notes under the 2025 indenture. We received approximately $308.4 million in net proceeds, after deducting the initial purchaser's discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2025 notes. We used the net proceeds from the issuance of the new 2025 notes to repay a portion of the outstanding borrowings under our revolving credit facility.
The 2025 senior notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year and will mature on May 31, 2025. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2025 senior notes; provided, however, that the 2025 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream Operating LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.
For additional information regarding the 2025 senior notes, see Note 9—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

Energen Notes
At the effective time of the merger, Energen became our wholly owned subsidiary and remained the issuer of an aggregate principal amount of $530.0 million in notes, which we refer to as the Energen Notes, issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee, which we refer to as the Energen

Indenture. The Energen Notes consist of: (a) $400.0 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (b) $100.0 million of 7.125% notes due on February 15, 2028, (c) $20.0 million of 7.320% notes due on July 28, 2022, and (d) $10.0 million of 7.35% notes due on July 28, 2027.

The Energen Notes are the senior unsecured obligations of Energen and, post-merger, Energen, as our wholly owned subsidiary, continues to be the sole issuer and obligor under the Energen Notes. The Energen Notes rank equally in right of payment with all other senior unsecured indebtedness of Energen, including any unsecured guaranties by Energen of our indebtedness, and are effectively subordinated to Energen's senior secured indebtedness, including Energen's secured guaranty of all borrowings and other obligations under our revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

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For additional information regarding the Energen Notes, See Note 9—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

Second Amended and Restated Credit Facility

Our credit agreement dated November 1, 2013, as amended and restated, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger, provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on our oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, we and Wells Fargo each may request up to two interim redeterminations of the borrowing base during any 12-month period. As of December 31, 2018, the borrowing base was set at $2.65 billion, we had elected a commitment amount of $2.0 billion and we had borrowings of $1.5 billion outstanding under the revolving credit facility, of which approximately $559.0 million was used to by us to repay in full all borrowings under Energen's credit facility outstanding prior to the effective time of the merger.

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

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022.

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

Financial Covenant	Required Ratio
Ratio of total net debt to EBITDAX, as defined in the credit agreement	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 in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.

As of December 31, 2018, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Viper’s Facility-Wells Fargo Bank

On July 8, 2014, Viper entered into a secured revolving credit agreement, or revolving credit facility, with Wells Fargo, as administrative agent, certain other lenders, and the Operating Company, as guarantor. On May 8, 2018, the Operating Company

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assumed all liabilities as borrower under the credit agreement and Viper became a guarantor of the credit agreement. On July 20, 2018, the Operating Company, Viper, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company. The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on Viper's oil and natural gas reserves and other factors (the "borrowing base") of $555.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and October 26th. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of December 31, 2018, the borrowing base was set at $555.0 million, and Viper had $411.0 million of outstanding borrowings and $144.0 million available for future borrowings under its revolving credit facility.

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

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

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

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

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

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2019 capital budget for drilling and infrastructure of $2.7 billion to $3.0 billion, representing an increase of 85% over our 2018 capital budget. We estimate that, of these expenditures, approximately:

- $2.3 billion to $2.55 billion will be spent on drilling and completing 290 to 320 gross (255 to 280 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 9,400 feet;

- $400.0 million to $450.0 million will be spent on midstream infrastructure; and

- $175.0 million to $200.0 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

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During the year ended December 31, 2018, our aggregate capital expenditures for drilling and infrastructure were $1.5 billion. 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, 2018, we spent approximately $1.4 billion in cash on acquisitions of leasehold interests and mineral acres.

The amount and timing of our capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. We are currently operating 21 horizontal rigs and eight completion crews and currently intend to operate between 18 and 22 drilling rigs in 2019 across our asset base in the Midland and Delaware Basins. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Based upon current oil and natural gas price and production expectations for 2019, we believe that our cash flow from operations will be sufficient to fund our operations through year-end 2019. 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 2019 capital expenditure budget does not allocate any funds for leasehold and mineral interest acquisitions.

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

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2018:

	Payments Due by Period				
	2019	2020-2021	2022-2023	Thereafter	Total
	(in thousands)				
Secured revolving credit facility[1]	$—	$—	$1,489,500	$—	$1,489,500
Interest expense related to the secured revolving credit facility	1,914	3,829	1,594	—	7,337
Senior notes	—	—	—	2,050,000	2,050,000
Interest expense related to the senior notes[2]	102,375	204,750	204,750	212,805	724,680
Viper's secured revolving credit facility[1]	—	—	411,000	—	411,000
Interest and commitment fees under Viper's credit agreement[3]	540	1,080	450	—	2,070
Asset retirement obligations [4]	60	—	—	136,181	136,241
Drilling commitments[5]	18,976	414	—	—	19,390
Sand supply agreements	9,000	18,000	11,250	—	38,250

Operating lease obligations(6)	9,019	5,279	583	—	14,881
	$141,884	$233,352	$2,119,127	$2,398,986	$4,893,349

(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 and Energen Notes.

(3) Includes only the minimum amount of interest and commitment fees due which, as of December 31, 2018, includes a commitment fee equal to 0.375% per year of the unused portion of the borrowing base of Viper’s credit agreement.

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(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 7—Asset Retirement Obligations of the Notes to the Consolidated Financial Statements included elsewhere in 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, 2018.

(6) Operating lease obligations represent future commitments for building, equipment and vehicle leases.

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—Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements included elsewhere in 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.

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.

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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 natural 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 natural 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

Revenue from Contracts with Customers

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

Oil sales

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

Natural gas and natural gas liquids sales

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

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

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Midstream Revenue

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

Transaction price allocated to remaining performance obligations

Our upstream product sales contracts do not originate until production occurs and, therefore, are not considered to exist beyond each days' production. Therefore, there are no remaining performance obligation under any of our product sales contracts.
The majority of our midstream revenue agreements have a term greater than one year, and as such Rattler has utilized the practical expedient in ASC 606, which states that we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our revenue agreements, each delivery generally represents a separate performance obligation; therefore, future volumes delivered are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.
The remainder of our midstream revenue agreements, which relate to agreements with third parties, are short-term in nature with a term of one year or less. Rattler has utilized an additional practical expedient in ASC 606 which exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of an agreement that has an original expected duration of one year or less.

Contract balances

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

Prior-period performance obligations

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

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

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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 natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions 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 natural 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 and natural gas. 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, 2018, 2017 and 2016. 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 11–Equity-Based Compensation of the Notes to the Consolidated Financial Statements included elsewhere in the Form 10-K. 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.

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

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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.

Investments

Viper has an equity interest in a limited partnership that is so minor that Viper has no influence over the limited partnership's operating and financial policies. This interest was acquired during the year ended December 31, 2014 and was accounted for under the cost method. Effective January 1, 2018, Viper adopted Accounting Standards Update 2016-01 which requires Viper to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption. For the year ended December 31, 2018, Viper recorded a loss of $0.6 million. Viper's investment balance as of December 31, 2018 was $14.5 million, which is included in other assets in the accompanying consolidated balance sheets.

Funds Held in Escrow

The funds held in escrow represent amounts in deposit to fund acquisitions. During the year ended December 31, 2018, we did not have any funds held in escrow. During the year ended December 31, 2017, there was $6.3 million in deposit to fund other acquisitions which closed in the first quarter of 2018.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

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

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

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, "Leases". This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. We enter into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles and compressors. We have completed the process of reviewing and determining the contracts to which this new guidance applies. Upon adoption, on January 1, 2019, we recognized approximately $13.6 million of right-of-use assets, of which the total amount relates to our operating leases.

In January 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-01, “Leases - Land Easement Practical Expedient for Transition to Topic 842”. This update applies to any entity that holds land easements. The update allows entities to adopt a practical expedient to not evaluate existing or expired land easements under Topic 842 that were not previously accounted for as leases under the current leases guidance. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. We adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on our financial position, results of operations or liquidity.

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In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-10, "Codification Improvements to Topic 842, Leases". This update provides clarification and corrects unintended application of certain sections in the new lease guidance. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The adoption of this update did not have an impact on our financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-11, "Lease (Topic 842): Targeted Improvements". This update provides another transition method of allowing entities to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. We adopted this standard as of January 1, 2019. The primary impact of adopting this standard is the recognition of assets and liabilities on the balance sheet for current operating leases.

In December 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-20, "Leases (Topic 842) - Narrow-Scope Improvements for Lessors". This update provides a practical expedient for lessors to elect not to evaluate whether sales taxes and other similar taxes are lessor costs. The update also requires a lessor to exclude from variable payments those costs paid directly by the lessee to third parties and include lessor costs paid by the lessor and reimbursed by the lessee. We adopted this update effective January 1, 2019. The adoption of this standard did not have an effect on our financial position, results of operations or liquidity.

In August 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-15, "Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments". This update applies to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; including bank-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. We adopted this update effective January 1, 2018 using the retrospective transition method. Adoption of this standard did not have an effect on the presentation on the Statement of Cash Flows.

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

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

In June 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-07, "Stock Compensation - Improvements to Nonemployee Share-Based Payment Accounting". This update applies the existing employee guidance to nonemployee share-based transactions, with the exception of specific guidance related to the attribution of compensation cost. We adopted this standard effective January 1, 2019. The adoption of this standard did not have a material impact on our financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-09, “Codification Improvements”. This update provides clarification and corrects unintended application of the guidance in various sections. We adopted this standard effective January 1, 2019. The adoption of this update did not have a material impact on our financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In June 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-13, “Financial Instruments - Credit Losses”. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope

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that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We do not believe the adoption of this standard will have a material impact on our consolidated financial statements since we do not have a history of credit losses.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-13, “Fair Value Measurement (Topic 820) - Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement”. This update modifies the fair value measurement disclosure requirements specifically related to Level 3 fair value measurements and transfers between levels. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied prospectively. We are currently evaluating the impact of the adoption of this update, but do not believe it will have a material impact on our financial position, results of operations or liquidity.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-15, “Intangibles - Goodwill and Other - Internal - Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract”. This update requires the capitalization of implementation costs incurred in a hosting arrangement that is a service contract for internal-use software. Training and certain data conversion costs cannot be capitalized. The entity is required to expense the capitalized implementation costs over the term of the hosting agreement. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We believe the adoption of this update will not have an impact on our financial position, results of operations or liquidity.

In November 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-19, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses”. This update clarifies that receivables arising from operating leases are not in scope of this topic, but rather Topic 842, Leases. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We do not believe the adoption of this standard will have an impact on our financial statements since we do not have a history of credit losses.

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, 2018, 2017 and 2016. 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.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2018. Please read Note 17—Commitments and Contingencies included in Notes to the Consolidated Financial Statements included elsewhere in 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, including basis swaps and three-way collars, to reduce price volatility associated with certain of our oil and natural gas sales. With respect to these fixed price swap contracts, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX WTI

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(Cushing and Magellan East Houston) and Crude Oil - Brent and with natural gas derivative settlements based on NYMEX Henry Hub and Waha Hub.

At December 31, 2018, we had a net asset derivative position of $215.3 million as compared to a net liability derivative position of $106.1 million at December 31, 2017, related to our price swap, price basis swap derivatives and three-way collars. Utilizing actual derivative contractual volumes under our fixed price swaps and fixed price basis swaps as of December 31, 2018, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to $157.8 million, an increase of $57.6 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $272.9 million, a decrease of $57.6 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $95.5 million at December 31, 2018) and receivables from the sale of our oil and natural gas production (approximately $296.5 million at December 31, 2018).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the year ended December 31, 2018, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (26%); Koch Supply & Trading LP (15%); and Occidental Energy Marketing Inc (11%). For the year ended December 31, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (31%); Koch Supply & Trading LP (19%); and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2016, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (45%); Koch Supply & Trading LP (15%); and Enterprise Crude Oil LLC (13%). 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, 2018, we had four customers that represented approximately 82% of our total joint operations receivables. At December 31, 2017, we had three customer that represented approximately 74% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base.

As of December 31, 2018, we had $1.5 billion borrowings outstanding under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 4.10% on December 31, 2018. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $14.9 million based on the $1.5 billion outstanding in the aggregate under our revolving credit facility as of such date.

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.

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

Changes in Internal Control over Financial Reporting

As noted under “Management’s Report on Internal Control over Financial Reporting,” management’s assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the merger with Energen on November 29, 2018. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. The Company is in the process of integrating Energen’s and our internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. Except as noted above, there were no changes in our internal control over financial reporting that occurred during the fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control 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, 2018. Management’s assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the merger with Energen on November 29, 2018. Energen’s total assets and total operating revenue represented approximately 47% of the Company’s consolidated total assets at December 31, 2018 and 4.7% of the Company’s consolidated total operating revenue for the year ended December 31, 2018.

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, 2018. The report, which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting at December 31, 2018, 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.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the 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) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated February 22, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion
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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Our audit of, and opinion on, the Company's internal control over financial reporting does not include the internal control over financial reporting of Energen Corporation, a wholly-owned subsidiary, whose financial statements reflect total assets and revenues constituting 47.0 and 4.7 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2018. As indicated in Management's Report, Energen Corporation was acquired during 2018. Management's assertion on the effectiveness of the Company's internal control over financial reporting excluded internal control over financial reporting of Energen Corporation.

Definition and limitations of internal control over financial reporting
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.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 22, 2019

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, 2018.

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, 2018.

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, 2018.

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, 2018.

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, 2018.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. Financial Statements

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

Exhibit Number	Description
2.1#	Purchase and Sale Agreement, dated as of December 13, 2016, by and among Brigham Resources Operating, LLC and Brigham Resources Midstream, LLC, as sellers, and Diamondback E&P LLC and Diamondback Energy, Inc., as buyers (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 14, 2016).
2.2#	Agreement and Plan of Merger, dated as of August 14, 2018, by and among Diamondback Energy, Inc., Sidewinder Merger Sub Inc. and Energen Corporation (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on August 15, 2018).
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Certificate of Amendment No. 1 of the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 12, 2016).
3.3	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.4	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-35700, filed by the Company with the SEC on April 27, 2018).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Indenture, dated as of October 28, 2016, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Diamondback Energy, Inc.'s 4.750 % Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 2, 2016).
4.3	First Supplemental Indenture for the 4.750% Senior Notes due 2024, dated as of September 25, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 1, 2018).
4.4*	Second Supplemental Indenture for the 4.750% Senior Notes due 2024, dated as of October 12, 2018, among Sidewinder Merger Sub Inc., a subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee.
4.5*	Third Supplemental Indenture for the 4.750% Senior Notes due 2024, dated as of January 28, 2019, among Energen Corporation, Energen Resources Corporation, and EGN Services, Inc., each a direct or indirect subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee.
4.6	Indenture, dated as of December 20, 2016, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Diamondback Energy, Inc.'s 5.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 21, 2016).
4.7	First Supplemental Indenture for the 5.375% Senior Notes due 2025, dated as of January 29, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on January 30, 2018).
4.8*	Second Supplemental Indenture for the 5.375% Senior Notes due 2025, dated as of October 12, 2018, among Sidewinder Merger Sub Inc., a subsidiary of the Company, the Company, the other guarantors and Wells Fargo Bank, National Association, as trustee.
4.9*	

	Third Supplemental Indenture for the 5.375% Senior Notes due 2025, dated as of January 28, 2019, among Energen Corporation, Energen Resources Corporation, and EGN Services, Inc., each a direct or indirect subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee.
4.10	Registration Rights Agreement, dated as of February 28, 2017, among Diamondback Energy, Inc., Brigham Resources, LLC, Brigham Resources Operating, LLC and Brigham Resources Upstream Holdings, LP. (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001.35700, filed by the Company with the SEC on March 6, 2017).
4.11	Registration Rights Agreement, dated October 31, 2018, by and between Diamondback Energy, Inc. and Ajax Resources, LLC (incorporated by reference to Exhibit 4.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 7, 2018).

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3. Exhibits

Exhibit Number	Description
4.12	Registration Rights Agreement, dated September 25, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Goldman Sachs & Co. LLC (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 1, 2018).
4.13	Form of Indenture, dated September 1, 1996, between Energen and The Bank of New York as trustee (incorporated by reference to Exhibit 4(i) to Energen's Registration Statement on Form S-3 (Registration No. 333-11239), filed with the SEC on August 30, 1996).
10.1	Diamondback Energy, Inc. 2016 Amended and Restated Equity Incentive Plan (incorporated by reference to Appendix A to Schedule DEFA 14A filed by the Company with the SEC on May 25, 2016).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.13 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.3+	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.14 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.4+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.5+	Amended and Restated Employment Agreement, dated April 24, 2014, effective as of April 18, 2014, by and between Travis D. Stice and Diamondback E&P LLC (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 001-035700, filed by the Company with the SEC on May 9, 2014).
10.6+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Teresa Dick and Diamondback E&P LLC (incorporated by reference to Exhibit 10.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.7+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Michael Hollis and Diamondback E&P LLC (incorporated by reference to Exhibit 10.4 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.8+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Jeff White and Diamondback E&P LLC (incorporated by reference to Exhibit 10.5 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.9+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Russell Pantermuehl and Diamondback E&P LLC (incorporated by reference to Exhibit 10.6 to the Form 10-Q, File No. 001-035700, filed by the Company with the SEC on May 9, 2014).
10.10+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 2, 2014).
10.11+	Form of Time-Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.12+	Form of Performance-Based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.13+	Form of Amendment to Restricted Stock Unit Certificate (incorporated by reference to Exhibit 10.38 to the Form 10-K/A, file No. 001-35700, filed by the Company with the SEC on April 10, 2013).
10.14	Second Amended and Restated Credit Agreement, dated as of November 1, 2103, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 5, 2013).

10.15	First Amendment, dated June 9, 2014, to the Second Amended and Restated Credit Agreement, originally dated November 1, 2013, by and among the Company, as parent guarantor, Diamondback O&G LLC, as borrower, each of the guarantors party thereto, each of the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 7, 2014).
10.16	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of November 13, 2014, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, the guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 18, 2014).

3. Exhibits

Exhibit Number	Description
10.17	Third Amendment, dated as of June 21, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 27, 2016).
10.18	Fourth Amendment, dated as of December 15, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 20, 2016).
10.19	Fifth Amendment, dated as of November 28, 2017, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 4, 2017).
10.20	Eighth Amendment to the Second Amended and Restated Credit Agreement, dated as of October 26, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 1, 2018).
10.21	Ninth Amendment to Second Amended and Restated Credit Agreement and Fourth Amendment to Amended and Restated Guaranty and Collateral Agreement, dated as of November 29, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 6, 2018).
10.22	Contribution Agreement by and among Diamondback Energy, Inc., Viper Energy Partners LLC, Viper Energy Partners GP LLC and Viper Energy Partners LP, dated as of June 17, 2014 (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by Viper Energy Partners LP with the SEC on May 7, 2014).
10.23	Amended and Restated Credit Agreement, dated as of July 20, 2018, by and among, Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K (File 001-36505) filed by Viper Energy Partners LP on July 26, 2018).
10.24	ATM Equity OfferingSM Sales Agreement, dated December 11, 2018, by and among Diamondback Energy, Inc., Ajax Resources, LLC, F&A Wylie Investments, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as sales agent (incorporated by reference to 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 12, 2018).
10.25+	Energen Corporation Stock Incentive Plan (as amended effective November 7, 2017) (incorporated by reference to Exhibit 10(b) to Energen's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017).
10.26+	Amendment to the Energen Corporation Stock Incentive Plan, dated November 27, 2018 (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8, File No. 333-228637, filed by the

	Company with the SEC on November 30, 2018).
10.27+	Form of Stock Option Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10(r) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012).
10.28+	Form of Restricted Stock Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10(s) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012).
10.29+	Form of Restricted Stock Unit Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Energen's Current Report on Form 8-K filed December 12, 2013).
10.30+	Form of Performance Share Award under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10(t) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.

3. Exhibits

Exhibit Number	Description
23.2*	Consent of Ryder Scott Company, L.P. with respect to the Diamondback Energy, Inc. reserve report included as Exhibit 99.1.
23.3*	Consent of Ryder Scott Company, L.P. with respect to the Viper Energy Partners LP reserve report included as Exhibit 99.2.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Ryder Scott Company, L.P., dated January 18, 2019, with respect to an estimate of the proved reserves, future production and income attributable to certain leasehold interests of Diamondback Energy, Inc. as of December 31, 2018.
99.2*	Report of Ryder Scott Company, L.P., dated January 18, 2019, with respect to an estimate of the proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP, a subsidiary of Diamondback Energy, Inc., as of December 31, 2018.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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* Filed herewith.

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

\+ Management contract, compensatory plan or arrangement.

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

ITEM 16. FORM 10-K SUMMARY

None

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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 22, 2019

/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 22, 2019
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 22, 2019
/s/ Michael P. Cross Michael P. Cross	Director	February 22, 2019
/s/ Michael L. Hollis Michael L. Hollis	President, Chief Operating Officer and Director	February 22, 2019
/s/ David L. Houston David L. Houston	Director	February 22, 2019
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 22, 2019
/s/ Melanie M. Trent Melanie M. Trent	Director	February 22, 2019
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer, Senior Vice President, and Assistant Secretary (Principal Financial and Accounting Officer)	February 22, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (collectively the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2018, 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 22, 2019 expressed an unqualified opinion.

Basis for opinion
These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2009.

Oklahoma City, Oklahoma
February 22, 2019

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
	2018	2017
	(In thousands, except share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$214,516	$112,446
Accounts receivable:		
Joint interest and other, net	95,536	73,038
Oil and natural gas sales	296,525	158,575
Inventories	37,570	9,108
Derivative instruments	230,527	531
Prepaid expenses and other	50,347	4,903
Total current assets	925,021	358,601
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($9,669,977 and $4,105,865 excluded from amortization at December 31, 2018 and 2017, respectively)	22,299,182	9,232,694
Midstream assets	700,295	191,519
Other property, equipment and land	146,963	80,776
Accumulated depletion, depreciation, amortization and impairment	(2,774,465)	(2,161,372)
Net property and equipment	20,371,975	7,343,617
Funds held in escrow	—	6,304
Deferred tax asset	96,670	—
Investment in real estate, net	115,625	—
Other assets	86,396	62,463
Total assets	$21,595,687	$7,770,985
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$127,979	$94,590
Accrued capital expenditures	495,089	221,256
Other accrued liabilities	253,272	92,512
Revenues and royalties payable	143,272	68,703
Derivative instruments	—	100,367
Total current liabilities	1,019,612	577,428
Long-term debt	4,464,338	1,477,347
Derivative instruments	15,192	6,303
Asset retirement obligations	136,181	20,122
Deferred income taxes	1,784,532	108,048
Other long-term liabilities	9,570	—
Total liabilities	7,429,425	2,189,248
Commitments and contingencies (Note 17)		
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 164,273,447 issued and outstanding at December 31, 2018; 200,000,000 shares authorized, 98,167,289 issued and	1,643	982

outstanding at December 31, 2017		
Additional paid-in capital	12,935,885	5,291,011
Retained earnings (accumulated deficit)	761,833	(37,133)
Accumulated other comprehensive income	(74)	—
Total Diamondback Energy, Inc. stockholders’ equity	13,699,287	5,254,860
Non-controlling interest	466,975	326,877
Total equity	14,166,262	5,581,737
Total liabilities and equity	$21,595,687	$7,770,985

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2018	2017	2016
	(In thousands, except per share amounts)		
Revenues:			
Oil sales	$1,878,625	$1,044,017	$470,528
Natural gas sales	61,046	52,210	22,506
Natural gas liquid sales	190,109	90,048	34,073
Lease bonus	2,920	11,764	—
Midstream services	34,254	7,072	—
Other operating income	9,302	—	—
Total revenues	2,176,256	1,205,111	527,107
Costs and expenses:			
Lease operating expenses	204,975	126,524	82,428
Production and ad valorem taxes	132,661	73,505	34,456
Gathering and transportation	26,113	12,834	11,606
Midstream services	71,878	10,409	—
Depreciation, depletion and amortization	623,039	326,759	178,015
Impairment of oil and natural gas properties	—	—	245,536
General and administrative expenses	64,554	48,669	42,619
Asset retirement obligation accretion	2,132	1,391	1,064
Merger and integration expense	36,831	—	—
Other operating expense	3,285	—	—
Total costs and expenses	1,165,468	600,091	595,724
Income (loss) from operations	1,010,788	605,020	(68,617)
Other income (expense):			
Interest expense, net	(87,276)	(40,554)	(40,684)
Other income, net	88,996	10,235	3,064
Gain (loss) on derivative instruments, net	101,299	(77,512)	(25,345)
Loss on revaluation of investment	(550)	—	—
Loss on extinguishment of debt	—	—	(33,134)
Total other income (expense), net	102,469	(107,831)	(96,099)
Income (loss) before income taxes	1,113,257	497,189	(164,716)
Provision for (benefit from) income taxes	168,362	(19,568)	192
Net income (loss)	944,895	516,757	(164,908)
Net income attributable to non-controlling interest	99,223	34,496	126
Net income (loss) attributable to Diamondback Energy, Inc.	$845,672	$482,261	$(165,034)
Earnings per common share:			
Basic	$8.09	$4.95	$(2.20)
Diluted	$8.06	$4.94	$(2.20)
Weighted average common shares outstanding:			
Basic	104,622	97,458	75,077
Diluted	104,929	97,688	75,077

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income

	Year Ended December 31, 2018		
	2018	2017	2016
	(In thousands)		
Net income	$944,895	$516,757	$(164,908)
Other comprehensive income:			
Postretirement plans:			
Current period change in fair value of postretirement plans, net of tax of $0, $0 and $0, respectively	(74)	—	—
Total other comprehensive income, net of tax	(74)	—	—
Comprehensive income (loss)	944,821	516,757	(164,908)
Comprehensive income attributable to noncontrolling interest	—	—	—
Comprehensive income (loss) attributable to Diamondback Energy, Inc.	$944,821	$516,757	$(164,908)

See accompanying notes to consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	(In thousands)						
Balance December 31, 2015	66,797	$ 668	$ 2,229,664	$ (354,360)	$ —	$ 233,001	$ 2,108,973
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	—	93,462	93,462
Unit-based compensation		—	—	—	—	3,815	3,815
Distribution to non-controlling interest		—	—	—	—	(9,574)	(9,574)
Stock-based compensation		—	29,717	—	—	—	29,717
Common shares issued in public offering, net of offering costs	23,000	229	1,956,079	—	—	—	1,956,308
Exercise of stock options and vesting of restricted stock units	347	4	495	—	—	—	499
Net income (loss)		—	—	(165,034)	—	126	(164,908)
Balance December 31, 2016	90,144	901	4,215,955	(519,394)	—	320,830	4,018,292
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	—	369,896	369,896
Unit-based compensation		—	—	—	—	2,395	2,395
Common units issued for acquisition		—	—	—	—	3,050	3,050
Stock-based compensation		—	31,783	—	—	—	31,783
Distribution to non-controlling interest		—	—	—	—	(41,367)	(41,367)
Common shares issued in public offering, net of offering costs		—	14	—	—	—	14
Common shares issued for Brigham	7,686	77	809,096	—	—	—	809,173
Exercise of stock options and vesting of restricted stock units	337	4	355	—	—	—	359
Change in ownership of consolidated subsidiaries, net		—	233,808	—	—	(362,423)	(128,615)
Net income		—	—	482,261	—	34,496	516,757
Balance December 31, 2017	98,167	982	5,291,011	(37,133)	—	326,877	5,581,737
Impact of adoption of ASU 2016-01, net of tax		—	—	(9,393)	—	(6,671)	(16,064)
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	—	303,121	303,121
Unit-based compensation		—	—	—	—	2,763	2,763
	63,126	631	7,069,489	—	—	—	7,070,120

Common shares issued for business combination							
Stock options assumed in business combination		—	14,088	—	—	—	14,088
Restricted stock units assumed in business combination		—	51,829	—	—	—	51,829
Repurchased shares for tax withholding	(140)	—	(14,460)	—	—	—	(14,460)
Stock-based compensation		—	34,035	—	—	—	34,035

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	Shares	Amount					
Distribution to non-controlling interest		—	—	—	—	(98,345)	(98,345)
Common shares issued for Ajax	2,584	25	339,975	—	—	—	340,000
Dividend paid		—	—	(37,313)	—	—	(37,313)
Exercise of unit options and awards of restricted stock	536	5	(5)	—	—	140	140
Other comprehensive income, net of tax		—	—	—	(74)	—	(74)
Change in ownership of consolidated subsidiaries, net		—	149,923	—	—	(160,133)	(10,210)
Net income		—	—	845,672	—	99,223	944,895
Balance December 31, 2018	164,273	$ 1,643	$ 12,935,885	$ 761,833	$ (74)	$ 466,975	$ 14,166,262

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,		
	2018	2017	2016
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$944,895	$516,757	$(164,908)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for (benefit from) deferred income taxes	169,357	(20,567)	—
Impairment of oil and natural gas properties	—	—	245,536
Asset retirement obligation accretion	2,132	1,391	1,064
Depreciation, depletion and amortization	623,039	326,759	178,015
Amortization of debt issuance costs	11,613	3,943	2,717
Loss on early extinguishment of debt	—	—	33,134
Change in fair value of derivative instruments	(221,732)	84,240	26,522
Income from equity investment	—	(657)	(676)
Loss on revaluation of investment	550	—	—
Equity-based compensation expense	26,764	25,537	26,453
Loss (gain) on sale of assets, net	3,081	(455)	(61)
Changes in operating assets and liabilities:			
Accounts receivable	13,160	(97,611)	(35,030)
Accounts receivable-related party	—	297	1,294
Restricted cash	—	500	—
Inventories	(14,774)	(2,245)	(255)
Prepaid expenses and other	24,688	(11,362)	(709)
Accounts payable and accrued liabilities	(6,846)	36,762	15,922
Accounts payable and accrued liabilities-related party	—	(2)	(216)
Income tax payable	(814)	814	—
Accrued interest	(22,203)	(20,774)	(3,161)
Revenues and royalties payable	11,595	45,298	6,439
Net cash provided by operating activities	1,564,505	888,625	332,080
Cash flows from investing activities:			
Additions to oil and natural gas properties	(1,460,509)	(792,599)	(362,450)
Additions to oil and natural gas properties-related party	—	—	(637)
Additions to midstream assets	(204,222)	(68,139)	(1,188)
Purchase of other property, equipment and land	(6,840)	(22,779)	(9,891)
Acquisition of leasehold interests	(1,370,951)	(1,960,591)	(611,280)
Acquisition of mineral interests	(440,303)	(407,450)	(205,721)
Acquisition of midstream assets	—	(50,279)	—
Proceeds from sale of assets	80,098	65,656	4,661
Investment in real estate	(110,685)	—	—
Funds held in escrow	10,989	104,087	(121,391)
Purchase of other investments	(8)	—	—
Equity investments	(612)	(188)	(2,345)
Net cash used in investing activities	(3,503,043)	(3,132,282)	(1,310,242)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	2,651,500	753,500	164,000

Repayment under credit facility	(1,241,500)	(383,500)	(89,000)
Repayment on Energen's credit facility	(559,000)	—	—
Proceeds from senior notes	1,062,000	—	1,000,000

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

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Repayment of senior notes	—	—	(450,000)
Premium on extinguishment of debt	—	—	(26,561)
Debt issuance costs	(25,461)	(9,296)	(15,063)
Public offering costs	(2,652)	(510)	(1,182)
Proceeds from public offerings	305,773	370,344	2,051,503
Proceeds from exercise of unit options	140	—	—
Proceeds from exercise of stock options	—	358	498
Repurchased shares for tax withholdings	(14,460)	—	—
Dividends to stockholders	(37,313)	—	—
Other postemployment benefit changes	(74)	—	—
Distributions to non-controlling interest	(98,345)	(41,367)	(9,574)
Net cash provided by financing activities	2,040,608	689,529	2,624,621
Net increase (decrease) in cash and cash equivalents	102,070	(1,554,128)	1,646,459
Cash and cash equivalents at beginning of period	112,446	1,666,574	20,115
Cash and cash equivalents at end of period	$214,516	$112,446	$1,666,574
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$113,932	$57,668	$38,177
Cash paid for income taxes	$689	$—	$192
Supplemental disclosure of non-cash transactions:			
Change in accrued capital expenditures	$273,833	$160,906	$413
Capitalized stock-based compensation	$10,034	$8,641	$7,079
Common stock issued for Ajax	$340,000	$—	$—
Common stock issued for Brigham	$—	$809,173	$—
Common stock issued for business combination[1]	$7,136,037	$—	$—
Asset retirement obligations acquired	$111,197	$2,432	$3,696

(1) Includes $7,070,120 Common stock issued for business combination, $14,088 for stock options assumed and $51,829 for restricted stock units assumed.

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, 2018, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company and Rattler Midstream GP LLC, a Delaware limited liability company. The consolidated subsidiaries include the wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership (the “Partnership”), the Partnership’s wholly-owned subsidiary Viper Energy Partners LLC, a Delaware limited liability company (the “Operating Company”), Rattler Midstream LP (formerly known as Rattler Midstream Partners LP), a Delaware limited liability company, Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC), a Delaware limited liability company, and Rattler Midstream Operating LLC’s wholly-owned subsidiary Tall City Towers 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, 2018, the Company owned approximately 59% of the total units outstanding 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, but are not limited to, 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

In 2014, a subsidiary of the Company entered into an agreement to purchase certain overriding royalty interests and deposited $0.5 million in escrow. The subsidiary subsequently terminated the agreement and requested a return of the deposit. The seller challenged the termination and the escrow agent tendered the deposit to the court subject to a judicial determination of the proper payment of the funds. The parties reached a settlement of this matter in April 2017 and the funds were distributed in accordance with the terms of the settlement. Pending such distribution, these funds were classified as restricted cash.

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 for production 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. At December 31, 2018, the Company recorded an allowance for doubtful accounts of $2.0 million related to joint interest receivables. No allowance was deemed necessary at December 31, 2017.

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 for each period 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 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 fair value of the senior notes are determined using quoted market prices. Derivatives are recorded at fair value (see Note 16–Fair Value Measurements).

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

Prepaid Expenses and Other

Prepaid expenses and other consist of the following:

	Year Ended December 31,	
	2018	2017
Prepaid insurance	$4,303	$1,273
Prepaid fees and licenses	2,944	2,250
Income tax receivable	37,858	—
Other	5,242	1,380
Total prepaid expenses and other	$50,347	$4,903

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. Costs, including related employee costs, associated with production and operation of the properties are charged to expense as incurred. All other internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. 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 8–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 $12.62, $11.11 and $11.23 for the years ended December 31, 2018, 2017 and 2016, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $594.8 million, $321.9 million and $176.4 million for the years ended December 31, 2018, 2017 and 2016, 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 natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions, 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, 2016, the Company recorded an impairment on proved oil and natural gas properties of $245.5 million. No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2018 and 2017.

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.

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

Real Estate Assets

Real estate assets are stated at cost, less accumulated depreciation and amortization. The Company considers the period of future benefit of each respective asset to determine the appropriate useful life and depreciation and amortization is calculated using the straight-line method over the assigned useful life.

Upon acquisition of real estate properties, the purchase price is allocated to tangible assets, consisting of land and building, and to identified intangible assets and liabilities, which may include the value of above market and below market leases and the value of in-place leases. The allocation of the purchase price is based upon the fair value of each component of the property. Although independent appraisals may be used to assist in the determination of fair value, in many cases these values will be based upon management’s assessment of each property, the selling prices of comparable properties and the discounted value of cash flows from the asset.

The fair values of above market and below market in-place leases will be recorded based on the present value (using an interest rate which reflects the risks associated with the leases acquired) of the difference between (i) the contractual amounts to be paid pursuant to the in-place leases and (ii) an estimate of fair market lease rates for the corresponding in-place leases measured over a period equal to the non-cancelable term of the lease including any bargain renewal periods. The above market and below market lease values will be capitalized as intangible lease assets or liabilities. Above market lease values will be amortized as an adjustment of rental income over the remaining term of the respective leases. Below market lease values will be amortized as an adjustment of rental income over the remaining term of the respective leases, including any bargain renewal periods. If a lease were to be terminated prior to its stated expiration, all unamortized amounts of above market and below market in-place lease values relating to that lease would be recorded as an adjustment to rental income.

The fair values of in-place leases will include estimated direct costs associated with obtaining a new tenant, and opportunity costs associated with lost rentals which are avoided by acquiring an in-place lease. Direct costs associated with obtaining a new tenant may include commissions, tenant improvements, and other direct costs and are estimated, in part, by management’s consideration of current market costs to execute a similar lease.

These direct costs will be included in intangible lease assets on the balance sheet and will be amortized to expense over the remaining term of the respective leases. The value of opportunity costs will be calculated using the contractual amounts to be paid pursuant to the in-place leases over a market absorption period for a similar lease. These intangibles will be included in intangible lease assets on the balance sheet and will be amortized to expense over the remaining term of the respective leases. If a lease were to be terminated prior to its stated expiration, all unamortized amounts of in-place lease assets relating to that lease would be expensed.

Other Property, Equipment and Land

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 $9.5 million, $1.4 million and $1.4 million for the years ended December 31, 2018, 2017 and 2016, 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 or if there is a change in the estimated liability, 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, 2018, 2017 and 2016, 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 unevaluated properties to their intended use. Capitalized interest cannot exceed gross interest expense. The Company capitalized interest of $32.8 million and $22.1 million for the years ended December 31, 2018 and 2017. The Company did not have any capitalized interest for the years ended December 31, 2016.

Inventories

Inventories are stated at the lower of cost or market and consist of tubular goods and equipment at December 31, 2018 and 2017. 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, 2018, 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 related to the credit facility of $27.5 million and $16.7 million, net of accumulated amortization of $9.4 million and $7.0 million, as of December 31, 2018 and 2017, respectively. Long-term debt included capitalized costs related to the senior notes of $31.5 million and $15.2 million, net of accumulated amortization of $15.4 million and $2.0 million, as of December 31, 2018 and 2017, respectively. The costs associated with the senior notes are being netted against the senior notes balances and are being amortized over the term of the senior notes using the effective interest method. The costs associated with the Company's credit facility that are included in other assets are being amortized over the term of the facility.

Other Accrued Liabilities

Other accrued liabilities consist of the following:

	December 31,	
	2018	2017
	(In thousands)	
Liability for drilling costs prepaid by joint interest partners	$16,182	$30,320
Interest payable	25,748	6,770

Lease operating expenses payable	59,455	27,850
Ad valorem taxes payable	49,160	3,306
Current portion of asset retirement obligations	60	1,163
Other	102,667	23,103
Total other accrued liabilities	$253,272	$92,512

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

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 that the Company has not yet distributed 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.

Revenue Recognition

Revenue from Contracts with Customers

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

Oil sales

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

Natural gas and natural gas liquids sales

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

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

Midstream Revenue

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

Transaction price allocated to remaining performance obligations

The Company's upstream product sales contracts do not originate until production occurs and, therefore, are not considered to exist beyond each days' production. Therefore, there are no remaining performance obligation under any of our product sales contracts.
The majority of the Company's midstream revenue agreements have a term greater than one year, and as such Rattler LLC has utilized the practical expedient in ASC 606, which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under its revenue agreements, each delivery generally represents a separate performance obligation; therefore, future volumes delivered are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.
The remainder of the Company's midstream revenue agreements, which relate to agreements with third parties, are short-term in nature with a term of one year or less. Rattler LLC has utilized an additional practical expedient in ASC 606 which exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of an agreement that has an original expected duration of one year or less.

Contract balances

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

Prior-period performance obligations

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

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, 2018, 2017 and 2016.

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over the limited partnership’s operating and financial policies. This interest was acquired during the year ended December 31, 2014 and was accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption. For the year ended December 31, 2018, the Partnership recorded a loss of $0.6 million. The Partnership's investment balance as of December 31, 2018 was $14.5 million, which is included in other assets in the accompanying consolidated balance sheets.

For additional information on the Company's investments, see Note 8–Equity Method Investments.

Funds Held in Escrow

The funds held in escrow represent amounts in deposit to fund acquisitions. During the year ended December 31, 2018, the Company did not have any funds held in escrow. During the year ended December 31, 2017, there was $6.3 million in deposit to fund other acquisitions which closed in the first quarter of 2018.

Accounting for Equity-Based Compensation

The Company grants various types of stock-based awards including stock options and restricted stock units. The Partnership grants various unit-based awards including unit options and phantom units to employees, officers and directors of the General Partner and the Company who perform services for the Partnership. These plans and related accounting policies are defined and described more fully in Note 11–Equity-Based Compensation. Equity 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, 2018, three purchasers each accounted for more than 10% of the Company's revenue: Shell Trading (US) Company (26%); Koch Supply & Trading LP (15%); and Occidental Energy Marketing Inc (11%). For the year ended December 31, 2017, three purchasers each accounted for more than 10% of the Company's revenue: Shell Trading (US) Company (31%); Koch Supply & Trading LP (19%); and Enterprise Crude Oil LLC (11%). For the year ended December 31, 2016, three purchasers each accounted for more than 10% of the Company's revenue: Shell Trading (US) Company (45%); Koch Supply & Trading LP (15%); and Enterprise Crude Oil LLC (13%). 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 (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (ii) 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, 2018, 2017 and 2016, the Company had no margin tax expense. The Company’s 2014, 2015, 2016, 2017 and 2018 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2018 we had an unrecognized tax benefit of $2.4 million. As of December 31, 2017, the Company had no unrecognized tax benefits that would have a material impact on the effective tax 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, 2018, 2017 and 2016, there was no interest or penalties associated with uncertain tax positions recognized in the Company’s consolidated financial statements.

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

Accumulated Other Comprehensive Income

The following table provides changes in the components of accumulated other comprehensive income, net of related income tax effects:

	(In thousands)
Balance as of December 1, 2018	$ —
Other comprehensive loss before reclassifications	(74)
Change in accumulated other comprehensive income	(74)
Balance as of December 31, 2018	$ (74)

Recent Accounting Pronouncements

Recently Adopted Pronouncements

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

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

In August 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-15, "Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments". This update applies to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; including bank-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The Company adopted this update effective January 1, 2018 using the retrospective transition method. Adoption of this standard did not have an effect on the presentation on the Statement of Cash Flows.

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

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

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

Accounting Pronouncements Not Yet Adopted

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, “Leases”. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles and compressors. The Company has completed the process of reviewing and determining the contracts to which this new guidance applies. Upon adoption on January 1, 2019, the Company recognized approximately $13.6 million of right-of-use assets, of which the total amount relates to the Company’s operating leases.

In January 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-01, “Leases - Land Easement Practical Expedient for Transition to Topic 842”. This update applies to any entity that holds land easements. The update allows entities to adopt a practical expedient to not evaluate existing or expired land easements under Topic 842 that were not previously accounted for as leases under the current leases guidance. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-10, “Codification Improvements to Topic 842, Leases”. This update provides clarification and corrects unintended application of certain sections in the new lease guidance. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-11, “Lease (Topic 842): Targeted Improvements”. This update provides another transition method of allowing entities to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In December 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-20, “Leases (Topic 842) - Narrow-Scope Improvements for Lessors”. This update provides a practical expedient for lessors to elect not to evaluate whether sales taxes and other similar taxes are lessor costs. The update also requires a lessor to exclude from variable payments those costs paid directly by the lessee to third parties and include lessor costs paid by the lessor and reimbursed by the lessee. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

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

In June 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-07, “Stock Compensation - Improvements to Nonemployee Share-Based Payment Accounting”. This update applies the existing employee guidance to nonemployee share-based transactions, with the exception of specific guidance related to the attribution of compensation cost. This update will be effective for financial statements issued for fiscal years beginning after December 15,

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

2018, including interim periods within that fiscal year. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-09, “Codification Improvements”. This update provides clarification and corrects unintended application of the guidance in various sections. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company adopted this standard effective January 1, 2019. The adoption of this updated did not have a material impact on its financial position, results of operations or liquidity.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-13, “Fair Value Measurement (Topic 820) - Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement”. This update modifies the fair value measurement disclosure requirements specifically related to Level 3 fair value measurements and transfers between levels. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied prospectively. The Company is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact on its financial position, results of operations or liquidity.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-15, “Intangibles - Goodwill and Other - Internal - Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract”. This update requires the capitalization of implementation costs incurred in a hosting arrangement that is a service contract for internal-use software. Training and certain data conversion costs cannot be capitalized. The entity is required to expense the capitalized implementation costs over the term of the hosting agreement. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In November 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-19, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses”. This update clarifies that receivables arising from operating leases are not in scope of this topic, but rather Topic 842, Leases. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company does not believe the adoption of this standard will have an impact on its financial statements since it does not have a history of credit losses.

3. ACQUISITIONS
2018 Activity

Tall City Towers LLC

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

Ajax Resources, LLC

On July 22, 2018, the Company entered into a definitive purchase agreement to acquire all leasehold interests and related assets of Ajax Resources, LLC, which include approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900.0 million in cash, subject to certain adjustments, and approximately 2.6 million shares of the Company's common stock of which approximately 0.5 million shares were placed in an indemnity escrow (the "Ajax acquisition"). This transaction closed on October 31, 2018 and was effective as of July 1, 2018. The cash portion of this transaction was funded through a combination of cash on hand, proceeds from the sale of mineral interests to the Partnership (described below), borrowing under the Company's revolving credit facility and a portion of the proceeds from the Company's September 2018 senior note offering. See Note 9—Debt for information relating to this offering.

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Notes to Consolidated Financial Statements-(Continued)

Drop-down Transaction

On August 15, 2018, the Company completed a transaction to sell to the Partnership mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by the Company, for $175.0 million (the "Drop-down Transaction").
ExL Petroleum Management, LLC and EnergyQuest II LLC

On September 21, 2018, the Company entered into two definitive purchase agreements to acquire leasehold interests and related assets, one with ExL Petroleum Management, LLC and ExL Petroleum Operating, Inc. and one with EnergyQuest II LLC, for an aggregate of approximately 3,646 net leasehold acres in the Northern Midland Basin for a total of $312.5 million in cash, subject to certain adjustments. These transactions closed on October 31, 2018 and were effective as of August 1, 2018. These transactions were funded through a combination of cash on hand, proceeds from the sale of assets to the Partnership (described below) and borrowing under the Company's revolving credit facility.

Energen Corporation Merger

On November 29, 2018, the Company completed its acquisition of Energen Corporation ("Energen") in an all-stock transaction (the " Merger"), which was accounted for as a business combination. The addition of Energen's assets increased the Company's assets to: (i) over 273,000 net Tier One acres in the Permian Basin, (ii) approximately 7,200 estimated total net horizontal Permian locations, and (iii) approximately 394,000 net acres across the Midland and Delaware Basins. Under the terms of the Merger, each share of Energen common stock was converted into 0.6442 of a share of the Company's common stock. The Company issued approximately 62.8 million shares of its common stock valued at a price of $112.00 per share on the closing date, resulting in total consideration paid by the Company to the former Energen shareholders of approximately $7.1 billion.

In connection with the closing of the Merger, the Company repaid outstanding principal under Energen's revolving credit facility and assumed all of Energen's long-term debt. See Note 9—Debt for additional information.

Purchase Price Allocation

The Merger has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Energen to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-acquisition contingencies, final tax returns that provide the underlying tax basis of Energen's assets and liabilities and final appraisals of assets acquired and liabilities assumed. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

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

The following table sets forth the Company's preliminary purchase price allocation:

	(In thousands)
Consideration:	
Fair value of the Company's common stock issued	$7,136,037
Total consideration	$7,136,037
Fair value of liabilities assumed:	
Current liabilities	$349,254
Asset retirement obligation	104,907
Long-term debt	1,087,244
Noncurrent derivative instruments	17,308
Deferred income taxes	1,402,834
Other long-term liabilities	6,087
Amount attributable to liabilities assumed	$2,967,634
Fair value of assets acquired:	
Total current assets	305,086
Oil and natural gas properties	9,270,692
Midstream assets	262,752
Investment in real estate	10,700
Other property, equipment and land	58,388
Asset retirement obligation	104,907
Other postretirement assets	2,944
Noncurrent income tax receivable, net	75,713
Other long term assets	12,489
Amount attributable to assets acquired	$10,103,671

The Company has included in its consolidated statements of operations revenues of $101.7 million and direct operating expenses of $17.1 million for the period from December 1, 2018 to December 31, 2018 due to the acquisition.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the years ended December 31, 2018 and 2017 have been prepared to give effect to the Merger as if it had occurred on January 1, 2017. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for Energen's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert Energen's outstanding shares of common stock and equity awards as of the closing date of the Merger, (ii) the depletion of Energen's fair-valued proved oil and natural gas properties and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of approximately $36.8 million for the year ended December 31, 2018 and acquisition-related costs incurred by Energen of $59.0 million. The pro forma results of operations do not include any cost savings or other synergies that may result from the Merger or any estimated costs that have been or will be incurred by the Company to integrate the Energen assets. The pro forma financial data does not include the results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material.

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

The pro forma consolidated statement of operations data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Merger taken place on January 1, 2017 and is not intended to be a projection of future results.

	Year Ended December 31,	
	2018	2017
	(in thousands, except per share amounts)	
Revenues	$3,531,609	$2,195,726
Income from operations	1,559,141	900,435
Net income	1,319,967	875,382
Basic earnings per common share	7.54	5.26
Diluted earnings per common share	7.53	5.24

2017 Activity

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

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

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

The Company has included in its consolidated statements of operations revenues of $81.4 million and direct operating expenses of $23.5 million for the period from February 28, 2017 to December 31, 2017 due to the acquisition.

Pro Forma Financial Information

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

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

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.

	Year Ended December 31,	
	2017	2016
	(in thousands, except per share amounts)	
Revenues	$1,228,040	$627,301
Income from operations	619,369	(12,812)
Net income	472,649	(109,229)
Basic earnings per common share	4.85	(1.45)
Diluted earnings per common share	4.84	(1.45)

2016 Activity

On September 1, 2016, the Company acquired from an unrelated third party leasehold interests and related assets in the Southern Delaware Basin for an aggregate purchase price of $558.5 million. This transaction included approximately 26,797 gross (19,262 net) acres primarily in Reeves and Ward counties. The Company financed this acquisition with net proceeds from the July 2016 equity offering discussed in Note 10—Capital Stock and Earnings Per Share and cash on hand.

4. VIPER ENERGY PARTNERS LP

The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Select 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 consolidated subsidiary of Diamondback, serves as the general partner of, and holds a general partner interest in, the Partnership. As of December 31, 2018, the Company owned approximately 59% of the Partnership’s total units outstanding.

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. In connection with the Viper Offering, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

During the year ended December 31, 2018, Diamondback received distributions of $155.1 million in respect of its interests in the Partnership and the Operating Company.

In August 2016, the Partnership completed an underwritten public offering of 8,050,000 common units, which included 1,050,000 common units issued pursuant to an option to purchase additional common units granted to the underwriter. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at $15.60 per unit, which is the price per common unit paid by the underwriter to the Partnership. Following the August 2016 public offering, Diamondback had an approximate 83% limited partner interest in the Partnership. The Partnership received net proceeds from this offering of approximately $125.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, which it used to fund an acquisition and repaid outstanding borrowings under its revolving credit facility.

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

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

In July 2017, the Partnership completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. In this offering, Diamondback purchased 700,000 common units, an affiliate of the General Partner purchased 3,000,000 common units and certain officers and directors of the Company and the General Partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. Following this offering, the Company had an approximate 64% limited partner interest in the Partnership. The Partnership received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which the Partnership used $152.8 million to repay all of the then-outstanding borrowings under the Partnership's revolving credit facility and the balance was used fund a portion of the purchase price for acquisitions and for general partnership purposes.

In July 2018, the Partnership completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, the Company owned approximately 59% of the Partnership's total units then outstanding. The Partnership received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under its revolving credit facility.

As a result of these public offerings and the Partnership's issuance of unit-based compensation, the Company's ownership percentage in the Partnership was reduced. During the year ended December 31, 2018, the Company recorded a $160.1 million decrease to Non-controlling interest in the Partnership with an increase to Additional paid-in capital, which represents the difference between the Company's share of the underlying net book value in the Partnership before and after the respective Partnership common unit transactions, on the Company's consolidated balance sheet.

Recapitalization, Tax Status Election and Related Transactions by Viper

In March 2018, the Partnership announced that the Board of Directors of the General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election. In connection with making this election, on May 9, 2018 the Partnership (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of the Operating Company, (iii) amended and restated its existing registration rights agreement with the Company and (iv) entered into an exchange agreement with the Company, the General Partner and the Operating Company. Simultaneously with the effectiveness of these agreements, the Company delivered and assigned to the Partnership the 73,150,000 common units the Company owned in exchange for (i) 73,150,000 of the Partnership's newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018 (the "Recapitalization Agreement"). Immediately following that exchange, the Partnership continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and the Company owned the remaining approximately 64% of the outstanding units issued by the Operating Company. Upon completion of the Partnership's July 2018 offering of units, it owned approximately 41% of the outstanding units issued by the Operating Company and the Company owned the remaining approximately 59%. The Operating Company units and the Partnership's Class B units owned by the Company are exchangeable from time to time for the Partnership's common units (that is, one Operating Company unit and one Partnership Class B unit, together, will be exchangeable for one Partnership common unit).

On May 10, 2018, the change in the Partnership's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) the Company made a cash capital contribution of $1.0 million to the Partnership in respect of the Class B units. The Company, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, the Company also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as the Partnership's general partner and the Company continues to control the Partnership. After the effectiveness of the tax status election and the completion of related transactions, the Partnership's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to the Partnership's business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to the Partnership's Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and the Partnership's Current Report on Form 8-K filed with the SEC on May 15, 2018.

Partnership Agreement

The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018 (the "Partnership Agreement"), requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership's behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership's business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on its behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership. For the year ended December 31, 2018 and 2017, the General Partner allocated $2.5 million to the Partnership.

Tax Sharing

In connection with the closing of the Viper Offering, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership's results are included in a 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. For the year ended December 31, 2018, the Partnership accrued state income tax expense of $0.2 million for its share of Texas margin tax for which the Partnership's results are included in a combined tax return filed by Diamondback.

Other Agreements

See Note 13—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 9—Debt for a description of this credit facility.

5. REAL ESTATE ASSETS

In conjunction with Diamondback's acquisition of Fasken Towers Tall Towers, the Company allocated the $109.7 million purchase price between real estate assets and intangible lease assets related to in-place and above-market leases. In addition, the Company owns a $1.3 million office building. The following schedules present the cost and related accumulated depreciation or amortization (as applicable) of Diamondback's real estate assets including intangible lease assets:

	Estimated Useful Lives (Years)	December 31, 2018 (in thousands)
Buildings	30	$ 92,349
Tenant improvements	15	4,160
Land	N/A	947
Land improvements	15	484
Total real estate assets		97,940
Less: accumulated depreciation		(3,970)
Total investment in land and buildings, net		$ 93,970

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	Weighted Average Useful Lives (Months)	December 31, 2018 (in thousands)
In-place lease intangibles	45	$ 10,866
Less: accumulated amortization		(3,076)
In-place lease intangibles, net		7,790
Above-market lease intangibles	45	3,623
Less: accumulated amortization		(459)
Above-market lease intangibles, net		3,164
Total intangible lease assets, net		$ 10,954

6. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31, 2018	2017
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$12,629,205	$5,126,829
Not subject to depletion	9,669,977	4,105,865
Gross oil and natural gas properties	22,299,182	9,232,694
Accumulated depletion	(1,599,111)	(1,009,893)
Accumulated impairment	(1,143,498)	(1,143,498)
Oil and natural gas properties, net	19,556,573	7,079,303
Midstream assets	700,295	191,519
Other property, equipment and land	146,963	80,776
Accumulated depreciation	(31,856)	(7,981)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$20,371,975	$7,343,617
Balance of costs not subject to depletion:		
Incurred in 2018	$6,223,817	
Incurred in 2017	2,500,003	
Incurred in 2016	696,751	
Incurred in 2015	182,194	
Incurred in 2014	67,212	
Total not subject to depletion	$9,669,977	

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. Costs, including related employee costs, associated with production and operation of the properties are charged to expense as incurred. All other internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. Capitalized internal costs were approximately $28.7 million $22.0 million and $17.2 million for the years ended December 31, 2018, 2017 and 2016, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years. Acquisition costs not currently being amortized are primarily related to unproved acreage that the Company plans to prove up through drilling. The Company has no plans to let any acreage expire. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as

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adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions, 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 2016, the Company recorded a non-cash ceiling test impairment for the year ended December 31, 2016 of $245.5 million, which is included in accumulated depletion. No impairments on proved oil and natural gas properties was recorded for the years ended December 31, 2018 and 2017. For 2016, the impairment charges affected the Company’s reported net income but did not reduce its cash flow. In addition to commodity prices, the Company’s production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

At December 31, 2018, there was $68.3 million in exploration costs and development costs and $54.9 million in capitalized interest that are not subject to depletion. At December 31, 2017, there were $26.0 million exploration costs and development costs and $22.1 million capitalized interest that are not subject to depletion.

7. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company’s asset retirement obligations liability for the following periods:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Asset retirement obligations, beginning of period	$21,285	$17,422	$12,711
Additional liabilities incurred	2,843	1,526	637
Liabilities acquired	111,197	2,432	3,696
Liabilities settled	(1,788)	(1,555)	(711)
Accretion expense	2,132	1,391	1,064
Revisions in estimated liabilities	572	69	25
Asset retirement obligations, end of period	136,241	21,285	17,422
Less current portion	60	1,163	1,288
Asset retirement obligations - long-term	$136,181	$20,122	$16,134

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.

8. EQUITY METHOD INVESTMENTS

In October 2014, the Company obtained a 25% interest in HMW Fluid Management LLC, which was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. During the year ended December 31, 2017, the Company invested $0.2 million in HMW LLC and recorded income of $0.7 million, which was the Company’s share of HMW Fluid Management LLC’s net income, bringing its total investment to $7.2 million at December 31, 2017. On June 30, 2018, HMW LLC’s operating agreement was amended effective January 1, 2018. As a result of the amendment, the Company will no longer recognize an equity investment in HMW LLC but will instead consolidate its undivided interest in the salt water disposal assets owned by HMW LLC as of January 1, 2018. In exchange for the Company’s 25% investment, the Company received a 50% undivided ownership interest in two of the four salt water disposal wells and associated assets previously owned by HMW LLC. The Company’s basis in the assets is equivalent to its basis in the equity investment in HMW LLC.

9. DEBT

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

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	December 31,	
	2018	2017
	(in thousands)	
4.625% Notes due 2021[1]	400,000	—
7.320% Medium-term Notes, Series A, due 2022[1]	20,000	—
4.750 % Senior Notes due 2024	1,250,000	500,000
5.375 % Senior Notes due 2025	800,000	500,000
7.350% Medium-term Notes, Series A, due 2027[1]	10,000	—
7.125% Medium-term Notes, Series B, due 2028[1]	100,000	—
Unamortized debt issuance costs	(26,645)	(13,153)
Unamortized premium costs	10,483	—
Revolving credit facility	1,489,500	397,000
Partnership revolving credit facility	411,000	93,500
Total long-term debt	$4,464,338	$1,477,347

(1) At the effective time of the Merger, Energen became a wholly owned subsidiary of the Company and remained the issuer of these notes (the “Energen Notes”).

Diamondback Notes

2024 Senior Notes

On October 28, 2016, the Company issued $500.0 million in aggregate principal amount of 4.750% Senior Notes due 2024 (the “existing 2024 Senior Notes”). The existing 2024 Senior Notes bear interest at a rate of 4.750% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017 and will mature on November 1, 2024. All of the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the existing 2024 Senior Notes, provided, however, that the existing 2024 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream Operating LLC, and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

On September 25, 2018, the Company issued $750.0 million aggregate principal amount of new 4.750% Senior Notes due 2024 (the “New 2024 Notes”), which together with existing Senior Notes are referred to as the 2024 Senior Notes, as additional notes under, and subject to the terms of, the 2024 Indenture. The New 2024 Notes were issued in a transaction exempt from the registration requirements under the Securities Act. The Company received approximately $740.7 million in net proceeds, after deducting the initial purchasers’ discount and its estimated offering expenses, but disregarding accrued interest, from the issuance of the New 2024 Notes. The Company used a portion of the net proceeds from the issuance of the New 2024 Notes to repay the outstanding borrowings under its revolving credit facility and used the balance for general corporate purposes, including funding a portion of the cash consideration for the acquisition of assets from Ajax Resources, LLC.

The 2024 Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented (the “2024 Indenture”). The 2024 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company’s restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries.

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

2025 Senior Notes

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

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

The 2025 Senior Notes were issued under an indenture, dated as of December 20, 2016, among the Company, the guarantors party thereto and Wells Fargo Bank, as the trustee (the "2025 Indenture"). The 2025 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company's ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries.

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

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Energen Notes

At the effective time of the Merger, Energen became the Company’s wholly owned subsidiary and remained the issuer of an aggregate principal amount of $530.0 million of the Energen Notes, issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee (the “Energen Indenture”). The Energen Notes consist of: (1) $400.0 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (2) $100.0 million of 7.125% notes due on February 15, 2028, (3) $20.0 million of 7.32% notes due on July 28, 2022, and (4) $10.0 million of 7.35% notes due on July 28, 2027.

The Energen Notes are the senior unsecured obligations of Energen and, post-merger, Energen, as a wholly owned subsidiary of the Company, continues to be the sole issuer and obligor under the Energen Notes. The Energen Notes rank equally in right of payment with all other senior unsecured indebtedness of Energen, including any unsecured guaranties by Energen of the Company’s indebtedness and are effectively subordinated to Energen’s senior secured indebtedness, including Energen’s secured guaranty of all borrowings and other obligations under the Company’s revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

The Energen Indenture contains certain covenants that, subject to certain exceptions and qualifications, limit Energen’s ability to incur or suffer to exist liens, to enter into sale and leaseback transactions, to consolidate with or merge into any other entity, and to convey, transfer or lease its properties and assets substantially as an entirety to any person or entity. The Energen Indenture not include a restriction on the payment of dividends.

On November 29, 2018, Energen guaranteed the Company’s indebtedness under its credit facility and granted a lien on certain of its assets to secure such indebtedness, and on December 21, 2018, Energen’s subsidiaries guaranteed the Company’s indebtedness under its credit agreement and granted liens on certain of their assets to secure such indebtedness. As a result of such guarantees, under the terms of the 2024 Indenture and the 2025 Indenture, Energen also guaranteed the 2024 Senior Notes and the 2025 Senior Notes.

The Company’s Credit Facility

The Company and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on the Company’s oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, the Company and Wells Fargo each may request up to two interim redeterminations of the borrowing base during any 12-month period. As of December 31, 2018, the borrowing base was set at $2.65 billion, the Company had elected a commitment amount of $2.0 billion and the Company had $1.5 billion of outstanding borrowings under the revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement. As of December 31, 2018, the credit agreement is guaranteed by the Company, Diamondback E&P LLC, Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC) and Energen and its subsidiaries and will also be guaranteed by any of the Company’s future subsidiaries that are classified as restricted subsidiaries under the credit agreement. The credit agreement is also secured by substantially all of the assets of the Company, Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Company that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5%, and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.25% in the case of the alternate base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a

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borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022.
The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

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

The covenant prohibiting additional indebtedness, as amended in November 2017, allows for the issuance of unsecured debt in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.
As of December 31, 2018 and 2017, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company’s revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

The Partnership’s Credit Agreement

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as administrative agent, certain other lenders and the Operating Company, the Partnership’s consolidated subsidiary, as guarantor. On May 8, 2018, the Operating Company assumed all liabilities as borrower under the credit agreement and the Partnership became a guarantor of the credit agreement. On July 20, 2018, the Operating Company, the Partnership, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company.

The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on the Partnership’s oil and natural gas reserves and other factors (the “borrowing base”) of $555.0 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and October 26th. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of December 31, 2018, the borrowing base was set at $555.0 million, and the Partnership had $411.0 million of outstanding borrowings and $144.0 million available for future borrowings under its revolving credit facility.

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

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

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

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

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

As of December 31, 2018 and 2017, the Partnership 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 Partnership's credit agreement 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.

Alliance with Obsidian Resources, L.L.C.

The Company entered into a participation and development agreement (the "DrillCo Agreement"), dated September 10, 2018, with Obsidian Resources, L.L.C. ("CEMOF") to fund oil and natural gas development. Funds managed by CEMOF and its affiliates have agreed to commit to funding certain costs out of CEMOF's net production revenue and, for a period of time, to the extent not funded by such revenue, up to an additional $300.0 million, to fund drilling programs on locations provided by the Company. Subject to adjustments depending on asset characteristics and return expectations of the selected drilling plan, CEMOF will fund up to 85% of the costs associated with new wells drilled under the DrillCo Agreement and is expected to receive an 80% working interest in these wells until it reaches certain payout thresholds equal to a cumulative 9% and then 13% internal rate of return. Upon reaching the final internal rate of return target, CEMOF's interest will be reduced to 15%, while the Company's interest will increase to 85%. As of December 31, 2018, CEMOF had not funded any amounts.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Interest expense	$110,252	$60,671	$39,642
Less capitalized interest	(32,812)	(22,097)	—
Other fees and expenses	10,403	2,160	1,426
Total interest expense	$87,843	$40,734	$41,068

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

10. CAPITAL STOCK AND EARNINGS PER SHARE

Diamondback did not complete any equity offerings during the years ended December 31, 2018 and 2017. Diamondback completed the following equity offerings during the year ended December 31, 2016:

Date	Number of Shares of Common Stock Sold	Number of Shares of Common Stock Issued to Underwriters	Price per Share Sold to Underwriters	Proceeds Received by the Company
January 2016	4,600,000	600,000	$ 55.33	$254,518
July 2016	6,325,000	825,000	$ 87.24	$551,777
December 2016	12,075,000	1,575,000	$ 95.3025	$1,150,828

Partnership Equity Offerings

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

In July 2017, the Partnership completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. In this offering, the Company purchased 700,000 common units, an affiliate of the General Partner purchased 3,000,000 common units and certain officers and directors of the Company and the General Partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. The Partnership received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which the Partnership used $152.8 million to repay all of the then-outstanding borrowings under the Partnership’s revolving credit facility and the balance was used to fund a portion of the purchase price for acquisitions and for general partnership purposes.

In July 2018, the Partnership completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, Diamondback owned approximate 59% of the total Partnership units then outstanding. The Partnership received net proceeds from this offering of approximately $303.1 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under its revolving credit facility.

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.

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

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per share amount)		
Net income (loss) attributable to common stock	$845,672	$482,261	$(165,034)
Weighted average common shares outstanding			
Basic weighted average common units outstanding	104,622	97,458	75,077
Effect of dilutive securities:			
Potential common shares issuable	307	230	—
Diluted weighted average common shares outstanding	104,929	97,688	75,077
Basic net income attributable to common stock	$8.09	$4.95	$(2.20)
Diluted net income attributable to common stock	$8.06	$4.94	$(2.20)

The Company had the following shares that were excluded from 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:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Restricted stock units	14	46	244

11. 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 2,276,548 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:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
General and administrative expenses	$26,764	$25,537	$26,453
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	10,034	8,641	7,079

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 8,967,545 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)

Restricted Stock Units

Under the Equity 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.

The following table presents the Company's restricted stock units activity under the Equity Plan during the year ended December 31, 2018:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	243,577	$ 90.88
Granted[(1)]	292,842	$ 120.30
Vested	(199,827)	$ 92.50
Forfeited	(12,368)	$ 102.41
Unvested at December 31, 2018	324,224	$ 116.01

(1) Includes 107,472 replacement awards granted in connection with the closing of the Energen merger on November 29, 2018.

The aggregate fair value of restricted stock units that vested during the year ended December 31, 2018, 2017 and 2016 was $18.5 million, $14.8 million and $12.5 million, respectively. As of December 31, 2018, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $21.2 million. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Performance-Based Restricted Stock Units

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

In February 2016, eligible employees received performance restricted stock unit awards totaling 174,325 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2016 to December 31, 2017 and vested at December 31, 2017. Eligible employees received additional performance restricted stock unit awards totaling 87,163 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2016 to December 31, 2018 and vested at December 31, 2018.

In February 2017, eligible employees received performance restricted stock unit awards totaling 37,440 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, 2017 to December 31, 2018 and vested at December 31, 2018. Eligible employees received additional performance restricted stock unit awards totaling 74,880 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, 2017 to December 31, 2019 and cliff vest at December 31, 2019.

In February 2018, eligible employees received performance restricted stock unit awards totaling 117,423 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2018 to December 31, 2020 and cliff vest at December 31, 2020.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period.

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

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

	2018	2017		2016	
	Three-Year Performance Period	Two-Year Performance Period	Three-Year Performance Period	Two-Year Performance Period	Three-Year Performance Period
Grant-date fair value	$ 170.45	$ 162.13	$ 168.73	$ 103.41	$ 102.35
Risk-free rate	1.99 %	1.27 %	1.59 %	0.86 %	1.10 %
Company volatility	35.90 %	39.32 %	41.14 %	41.91 %	42.16 %

The following table presents the Company’s performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2018:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	202,326	$ 139.83
Granted	285,737	$ 130.96
Vested	(291,860)	$ 81.21
Unvested at December 31, 2018[(1)]	196,203	$ 169.76

(1) A maximum of 392,406 units could be awarded based upon the Company’s final TSR ranking.

As of December 31, 2018, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $18.5 million. Such cost is expected to be recognized over a weighted-average period of 1.0 years.

Stock Appreciation Rights

In connection with the Energen merger, each outstanding stock appreciation right in respect of Energen common stock that was outstanding immediately prior to the effective time of the merger was converted into a fully vested stock appreciation right in respect of (i) that number of whole shares of Diamondback common stock (rounded down to the nearest whole share) equal to the product of (A) the total number of shares of Energen common stock subject to such stock appreciation right immediately prior to the effective time of the merger multiplied by (B) the exchange ratio, (ii) at an exercise price per share of Diamondback common stock (rounded up to the nearest whole cent) equal to the quotient of (A) the exercise price per share of Energen common stock of such stock appreciation right immediately prior to the effective time of the merger divided by (B) the exchange ratio. These awards have a three-year requisite service period.

A summary of stock appreciation rights activity as of December 31, 2018, and transactions during the month ended December 31, 2018 are presented below:

	Shares	Weighted Average Exercise Price

Outstanding at November 29,2018	—	$ —
Granted	57,721	22.12
Outstanding at December 31, 2018	57,721	$ 22.12

Stock Options

In connection with the Energen Merger, each option to purchase shares of Energen common stock that was outstanding immediately prior to the effective time of the merger was converted into a fully vested option to purchase (i) that number of whole shares of Diamondback common stock (rounded down to the nearest whole share) equal to the product of (A) the total number of shares of Energen common stock subject to such option immediately prior to the effective time of the merger multiplied

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by (B) the exchange ratio, (ii) at an exercise price per share of Diamondback common stock (rounded up to the nearest whole cent) equal to the quotient of (A) the exercise price per share of Energen common stock of such option immediately prior to the effective time divided by (B) the exchange ratio. The exercise price of stock options granted may not be less than the market value of the stock at the date of grant.

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 expected term of options granted was determined based on the contractual term of the awards at effective time of the merger. 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. All such amounts represent the weighted-average amounts for each year.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at November 29, 2018	—	$—		
Granted[1]	332,387	$95.04		
Outstanding at December 31, 2018	332,387	$95.04	2.82	$ 14,088
Vested and Expected to vest at December 31, 2018	332,387	$95.04	2.82	$ 14,088
Exercisable at December 31, 2018	332,387	$95.04	2.82	$ 14,088

(1)Conversion of stock options assumed in connection with the Energen Merger.

Phantom Units

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

The following table presents the phantom unit activity under the Viper LTIP for the year ended December 31, 2018:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	105,439	$ 17.10
Granted	127,402	$ 25.54
Vested	(102,811)	$ 19.23
Forfeited	(4,977)	$ 29.71
Unvested at December 31, 2018	125,053	$ 23.44

The aggregate fair value of phantom units that vested during the year ended December 31, 2018 was $2.0 million. As of December 31, 2018, the unrecognized compensation cost related to unvested phantom units was $1.6 million. Such cost is expected to be recognized over a weighted-average period of 0.98 years.

Partnership Unit Options

In accordance with the Viper LTIP, the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the Viper LTIP will consist of new common units of the Partnership. On June 17, 2014, the Board of Directors of the General Partner granted 2,500,000 unit options to the executive officers of the General Partner. The unit options vested 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). All outstanding unit options were amended effective November 29, 2016 to provide that vested unit options would become exercisable upon the earlier to occur of (i) the “Exercise Window Period” beginning on the third anniversary of the date of grant and ending on December 31, 2017, or (ii) the “Change of Control Exercise Period” beginning ten days before and ending on the date a change of control occurs (the earlier occurring of such

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events, the "Exercise Period"). At any time within the Exercise Period, if a participant attempted to exercise a vested unit option and the fair market value per unit as of such date was less than the exercise price per option unit, the vested unit option would not be exercisable. At the end of the Exercise Period, any vested unit option that was not exercisable or that had not been exercised would automatically terminate and become null and void.

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, 2018:

	Unit Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2017	7,600	$18.49		
Exercised	(7,600)	$18.49		
Outstanding at December 31, 2018	—	$—	0.00	$ —

The aggregate intrinsic value of unit options that were exercised during the year ended December 31, 2018 were $0.2 million.

12. ENERGEN EMPLOYEE BENEFIT PLANS

Plan Terminations: Energen terminated its qualified defined benefit pension plan on January 31, 2015 and distributed benefits in December 2015. In February 2018, Energen received notice that the Pension Benefit Guaranty Corporation had completed its audit of the termination of the pension plan and of the distribution of plan assets noting no exceptions.

Energen's non-qualified supplemental retirement plans were terminated effective December 31, 2014. Distributions under the plans were completed during the first quarter of 2016. The Company will not make any additional benefit payments with respect to the termination of the non-qualified supplemental retirement plans.

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Benefit Obligations: The following tables set forth the funded status of Energen’s postretirement health care and life insurance benefit plans and their reconciliation with the related amounts in the Company’s consolidated financial statements:

	One Month Ended December 31, 2018 (in thousands)
Change in Benefit Obligation	
Balance as of November 29, 2018	$ 5,373
Service cost	1
Interest cost	19
Actuarial gain	(35)
Plan amendments	—
Curtailment gain	—
Benefits paid	(7)
Balance at December 31, 2018	$ 5,351
Change in Plans' Assets	
Fair value of plan assets at November 29, 2018	$ 8,317
Actual return (loss) on plan assets	(90)
Benefits paid	(7)
Fair value of plan assets at December 31, 2018	$ 8,220
Funded status of plans	$ 2,869

	One Month Ended December 31, 2018 (in thousands)
Amounts recognized on consolidated balance sheets:	
Noncurrent assets recognized	$ 2,869
Amounts recognized to accumulated other comprehensive income:	
Prior service credit, net of taxes	$ —
Net actuarial loss, net of taxes	74
Total accumulated other comprehensive income	$ 74

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The components of net periodic benefit cost were as follows:

	One Month Ended December 31, 2018 (in thousands)
Postretirement Benefit Plans	
Components of net periodic benefit cost:	
Service cost	$ 1
Interest cost	19
Expected long-term return on assets	(19)
Prior service cost amortization	—
Actuarial gain amortization	—
Settlement charge	—
Curtailment gain	—
Net periodic (income) expense	$ 1

Other changes in plan assets and projected benefit obligations recognized in other comprehensive income were as follows:

	One Month Ended December 31, 2018 (in thousands)
Postretirement Benefit Plans	
Net actuarial (gain) loss experienced during the year	$ 74
Net actuarial loss recognized as expense	—
Prior service cost recognized as income	—
Prior service credit during the year	—
Prior service cost amortization	—
Total recognized in other comprehensive income	$ 74

The weighted average rate assumptions to determine net periodic benefit costs were as follows:

	One Month Ended December 31, 2018
Postretirement Benefit Plans	
Discount rate	4.55 %

Expected long-term return on plan assets	4.55 %

The weighted average assumptions used to determine the postretirement benefit obligations at the measurement date were as follows:

	One Month Ended December 31, 2018
Discount rate	4.55 %

Investment Strategy: For Energen's postretirement benefit plan assets, Energen employed a total return investment approach whereby a mix of fixed income investments and equities are used to meet future plan obligations on a long-term basis

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Notes to Consolidated Financial Statements-(Continued)

with a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, corporate financial condition and market conditions.

Energen sought to maintain an appropriate level of diversification to minimize the risk of large losses in a single asset class. Accordingly, plan assets for the postretirement health care and life insurance benefit plan do not have a concentration of assets in a single entity, industry, commodity or class of investment find.

	Target	As of December 31, 2018
Asset category:		
Equity securities	21 %	20 %
Debt securities	74 %	76 %
Other	5 %	4 %
Total	100 %	100 %

Plan assets included in the funded status postretirement benefit plans were as follows:

	December 31, 2018		
(in thousands)	Level 1	Level 2	Total
United States equities	$146	$ —	$146
Global equities	1,461	—	1,461
Fixed income	6,256	—	6,256
Other	357	—	357
Total	$8,220	$ —	$8,220

13. 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, 2016, Wexford beneficially owned less than 1% of the Company's outstanding common stock. The Chairman of the Board of Directors of both the Company and the General Partner was a partner at Wexford until his retirement from Wexford effective December 31, 2016. Another partner at Wexford serves as a member of the Board of Directors of the General Partner. Beginning January 1, 2017, Wexford and entities affiliated with Wexford are no longer considered related parties of the Company and any expenses after December 31, 2016 are no longer classified as related party expenses.

Related Party Revenue and Expenses

During the year ended December 31, 2016, the Company paid $3.3 million in lease operating expenses and $2.2 million in general and administrative expenses to related parties. During the year ended December 31, 2016, the Company received $0.2 million in other income from related parties.

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 was terminated on November 12, 2018 with an effective date of December 31, 2018. The Company paid $0.5 million during the year ended December 31, 2016 under the Advisory Services Agreement.

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 Advisory Services Agreement was terminated on November 12, 2018 with an effective date of December 31, 2018. For the years ended December 31, 2018, 2017 and 2016, the Partnership did not pay any amounts under the Advisory Services Agreement.

Midland Leases

Effective May 15, 2011, the Company occupied corporate office space in the Fasken building in Midland, Texas under a lease with an initial term of five years. On November 10, 2014, the lease was amended to extend the term of the lease for an additional 10-year period and to increase the monthly base rent to $94,000 beginning in June 2016, with an increase of approximately 2% annually. On January 31, 2018, Tall City Towers LLC, a subsidiary of the Company, completed its acquisition of the Fasken Center Office Building.

Field Office Lease

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011. On March 1, 2014, the building was purchased by WT Commercial Portfolio, LLC, which is controlled by an affiliate of Wexford. The term of the lease expired on February 28, 2018. The monthly base rent was $11,000 and increased 3% annually on March 1 of each year. During the third quarter of 2014, the Company entered into a sublease with Bison, in which Bison leased the field office space on the same terms as the Company's lease for the remainder of the lease term. The Company paid rent of $0.2 million during the year ended December 31, 2016. The Company received payments of $0.2 million from Bison in respect of this sublease during the year ended December 31, 2016. During the second quarter of 2017, the sublease between the Company and Bison as well as the original lease between the Company and WT Commercial Portfolio, LLC were terminated.

Lease Bonus - The Partnership

During the year ended December 31, 2018, the Company paid the Partnership $2.5 million in lease bonus payments to extend the term of 13 leases, reflecting an average bonus of $4,149 per acre and $0.6 million in lease bonus payments for one new lease, reflecting an average bonus of $18,002 per acre. During the year ended December 31, 2017, the Company paid the Partnership $0.1 million in lease bonus payments to extend the term of two leases, reflecting an average bonus of $7,459 per acre. During the year ended December 31, 2016, the Company paid the Partnership $0.3 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $1,371 per acre.

14. 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. The Company and its subsidiaries, other than the Partnership and the Operating Company, file a federal corporate income tax return on a consolidated basis. As discussed further below, the Partnership is a taxable entity for federal income tax purposes effective May 10, 2018, and as such files a federal corporate income tax return including the activity of its investment in the Operating Company. The Partnership's provision for income taxes is included in the Company's consolidated income tax provision and, to the extent applicable, in net income attributable to the non-controlling interest.

The Tax Cuts and Jobs Act, a historic reform of the U.S. federal income tax statutes, was enacted on December 22, 2017. Among other significant features, the Tax Cut and Jobs Act reduces the maximum US federal corporate income tax rate from 35% to 21%, preserves long-standing upstream oil and gas tax provisions such as immediate deduction of intangible drilling costs, allows for immediate expensing of capital expenditures for tangible personal property for a period of time, modifies the provisions related to the limitations on deductions for executive compensation of publicly traded corporations, and enacts new limitations regarding the deductibility of interest expense.

As of the completion of the Company’s financial statements for the year ended December 31, 2017, the Company had substantially completed its accounting for the effects of the enactment of the Tax Cuts and Jobs Act and with respect to those items for which the Company’s accounting was not complete, the Company made reasonable estimates of the effects on its deferred tax balances.

To account for the effects of the Tax Cut and Jobs Act, the Company remeasured its deferred tax assets and liabilities based on the federal income and state income tax rates at which they are now expected to reverse, which is generally a federal income tax rate of 21%. The enacted rate change resulted in a non-cash decrease of approximately $67.9 million to the Company’s income tax provision for the period ended December 31, 2017 and a corresponding reduction to the Company’s net noncurrent

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Notes to Consolidated Financial Statements-(Continued)

deferred tax liability balance as of December 31, 2017. At December 31, 2018, the Company completed its accounting for all of the enactment-date income tax effects of the Tax Cuts and Jobs Act and has not made any adjustments to the provisional amounts recorded December 31, 2017.

The components of the Company's consolidated provision for income taxes for the years ended December 31, 2018, 2017 and 2016 are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Current income tax provision (benefit):			
Federal	$4	$—	$—
State	(999)	999	192
Total current income tax provision	(995)	999	192
Deferred income tax provision (benefit):			
Federal	161,354	(21,720)	(579)
State	8,003	1,153	579
Total deferred income tax provision (benefit)	169,357	(20,567)	—
Total provision for (benefit from) income taxes	$168,362	$(19,568)	$192

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

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Income tax expense (benefit) at the federal statutory rate(1)	$233,784	$174,016	$(57,694)
Impact of nontaxable noncontrolling interest	(5,107)	(12,073)	—
Income tax benefit relating to change in statutory tax rate	—	(67,938)	—
State income tax expense (benefit), net of federal tax effect	7,769	3,413	770
Non-deductible compensation	4,887	13,492	3,990
Change in valuation allowance	150	(127,485)	53,336
Deferred taxes related to change in the Partnership's tax status	(72,787)	—	—
Other, net	(334)	(2,993)	(210)
Provision for (benefit from) income taxes	$168,362	$(19,568)	$192

(1) The federal statutory rates for the years ended December 31, 2018, 2017 and 2016 were 21%, 35% and 35%, respectively.

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Notes to Consolidated Financial Statements-(Continued)

The components of the Company’s deferred tax assets and liabilities as of December 31, 2018 and 2017 are as follows:

	December 31,	
	2018	2017
	(In thousands)	
Deferred tax assets		
Net operating loss and other carryforwards	154,408	74,997
Derivative instruments	—	22,918
Stock based compensation	7,021	942
The Partnership's investment in the Operating Company	94,468	—
Other	8,634	2,464
Deferred tax assets	264,531	101,321
Valuation allowance	(13,932)	(104)
Deferred tax assets, net of valuation allowance	250,599	101,217
Deferred tax liabilities		
Oil and natural gas properties and equipment	1,825,237	202,997
Midstream assets	66,728	6,268
Derivative instruments	46,496	—
Total deferred tax liabilities	1,938,461	209,265
Net deferred tax liabilities	$1,687,862	$108,048

The Company had net deferred tax liabilities of approximately $1,687.9 million and $108.0 million at December 31, 2018 and 2017, respectively. On November 29, 2018, the Company completed its acquisition of Energen. For federal income tax purposes, the acquisition was a tax-free merger whereby the Company’s tax basis in Energen assets and liabilities was unaffected by the acquisition. As of December 31, 2018, the Company recorded a deferred tax liability of $1,402.8 million associated with the acquired assets, which includes deferred tax assets related to tax attributes acquired from Energen. The acquired tax attributes include federal net operating loss and credit carryforwards of approximately $13.5 million which are subject to an annual limitation under Internal Revenue Code Section 382. The Company expects that these tax attributes will be fully utilized prior to expiration. In addition, acquired tax attributes include state net operating loss carryforwards of approximately $13.6 million for which a valuation allowance has been provided as discussed further below, and $75.7 million of minimum tax credit carryforward which the Company anticipates will be fully refundable over the 2018 through 2021 tax years. The Company’s minimum tax credits, including those acquired from Energen, are classified as $38.2 million current and $38.2 million noncurrent income tax receivables on the balance sheet.

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. At December 31, 2018, the Company had approximately $395.1 million of federal NOLs expiring in 2032 through 2037 and $172.7 million of federal NOLs with an indefinite carryforward life, including NOLs acquired from Energen. The Company principally operates in the state of Texas and is subject to Texas Margin Tax, which currently does not include an 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.

As of December 31, 2018, the Company has a valuation allowance of $13.9 million for certain state NOL carryforwards, including $13.6 million acquired from Energen, which the Company does not believe are realizable as it does not anticipate future operations in those states. Management's assessment at each balance sheet date included consideration of all available positive and negative evidence including the anticipated timing of reversal of deferred tax liabilities. Management believes that the balance of the Company's NOLs are realizable to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. As a result of management's assessment, in the quarter ended December 31, 2017, the Company had removed its valuation allowance against its federal NOLs and other federal deferred tax assets in order to state its deferred assets and liabilities at the amount more likely than not to be realized. As of December 31, 2018, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

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As discussed further in Note 4—Viper Energy Partners LP, on March 29, 2018, the Partnership announced that the Board of Directors of its General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. The transactions undertaken in connection with the change in the Partnership's tax status were not taxable to the Company. Subsequent to the Partnership's change in tax status, the Partnership's provision for income taxes for the period ended December 31, 2018 is based on its estimated annual effective tax rate plus discrete items. As such, the Partnership's provision for income taxes is included in the Company's consolidated financial statements and to the extent applicable, in net income attributable to the non-controlling interest.

At December 31, 2018, the Company's net deferred tax liabilities include a deferred tax asset of approximately $94.5 million related to the Partnership's investment in the Operating Company, approximately $72.8 million of which was recorded as a result of the Partnership's change in tax status. Under federal income tax provisions applicable to the Partnership's change in tax status, the Partnership's basis for federal income tax purposes in its interest in the Operating Company consists primarily of the sum of the Partnership's unitholders' tax bases in their interests in the Partnership on the date of the tax status change. Under federal income tax reporting rules applicable to publicly traded partnerships ("PTPs"), partner information, including partner tax basis information, is required to be provided to the Partnership, but not in sufficient time for the Partnership to finalize its determination of the resultant tax basis in the Operating Company. The deferred tax asset reflected above represents the Partnership's best estimate of the difference between its tax basis and its basis for financial accounting purposes in the Operating Company. The estimate is subject to revision when the Partnership finalizes its federal income tax computations for 2018. The Partnership has federal net operating loss carryforwards of approximately $8.3 million which may be carried forward indefinitely to offset future taxable income.

The following table sets forth changes in the Company's unrecognized tax benefits:

	December 31, 2018 (in thousands)
Balance at beginning of year	—
Increase resulting from tax positions acquired	7,111
Increase resulting from prior period tax positions	4
Increase resulting from current period tax positions	—
Balance at end of year	7,115
Less: Effects of temporary items	(4,666)
Total that, if recognized, would impact the effective income tax rate as of the end of the year	2,449

The Company's federal and state income tax returns for 2012 through the current tax year remain open and subject to examination by the IRS and major state taxing jurisdictions. Energen is currently under IRS examination of its federal consolidated income tax returns for 2014 and 2016. Accordingly, it is reasonably possible that significant changes to the reserve for uncertain tax positions may occur as a result of various audits and the expiration of the statute of limitations. Although the timing and outcome of tax examinations is highly uncertain, the Company does not expect the change in unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

15. DERIVATIVES

All derivative financial instruments are recorded at fair value in the accompanying balance sheet. 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 fixed price swap contracts, fixed price basis swap contracts and three-way costless collars with corresponding put, short put and call options to reduce price volatility associated with certain of its oil and natural gas sales. With respect to the Company’s fixed price swap and fixed price basis contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company

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has fixed price basis swaps for the spread between the WTI Magellan East Houston oil price and the WTI Cushing oil price and for the spread between the Henry Hub natural gas price and the Waha Hub natural gas price.

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

The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing (Cushing and Magellan East Houston) and ICE Brent pricing, and with natural gas derivative settlements based on New York Mercantile Exchange Henry Hub pricing and Waha Hub pricing and liquids derivative settlements based on Mt. Belvieu pricing.

By using derivative instruments to economically 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, 2018, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed:

	2019		2020	
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
Oil Swaps - WTI Cushing	10,638,000	$ 61.07	0	$ —
Oil Swaps - WTI Magellan East Houston	1,270,000	$ 72.39	0	$ —
Oil Swaps - BRENT	2,005,000	$ 68.02	0	$ —
Oil Basis Swaps - WTI Cushing	17,012,000	$ (5.56)	15,120,000	$ (1.21)
Natural Gas Swaps - Henry Hub	25,550,000	$ 3.06	0	$ —
Natural Gas Basis Swaps - Waha Hub	18,250,000	$ (1.60)	0	$ —
Natural Gas Liquid Swaps - Mont Belvieu	2,760,000	$ 27.30	0	$ —

	January 2019 - December 2019		
Oil Three-Way Collars	WTI Cushing	Brent	WTI Magellan East Houston

Volume (Bbls)	7,570,000	2,000,000	994,000
Short put price (per Bbl)	$38.10	$ 55.00	$ 56.82
Floor price (per Bbl)	$48.10	$ 65.00	$ 66.82
Ceiling price (per Bbl)	$63.70	$ 82.47	$ 77.60

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.

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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, 2018 and 2017.

	December 31,	
	2018	2017
	(in thousands)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$230,527	$531
Net amounts of assets presented in the Consolidated Balance Sheet	230,527	531
Gross amounts of liabilities presented in the Consolidated Balance Sheet	15,192	106,670
Net amounts of liabilities presented in the Consolidated Balance Sheet	$15,192	$106,670

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

	December 31,	
	2018	2017
	(in thousands)	
Current assets: derivative instruments	$230,527	$531
Noncurrent assets: derivative instruments	—	—
Total assets	$230,527	$531
Current liabilities: derivative instruments	$—	$100,367
Noncurrent liabilities: derivative instruments	15,192	6,303
Total liabilities	$15,192	$106,670

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Change in fair value of open non-hedge derivative instruments	$221,732	$(84,240)	$(26,522)
Gain (loss) on settlement of non-hedge derivative instruments	(120,433)	6,728	1,177
Gain (loss) on derivative instruments	$101,299	$(77,512)	$(25,345)

16. 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.

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Notes to Consolidated Financial Statements-(Continued)

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.

The Company estimates the fair values of proved oil and natural gas properties assumed in business combinations using discounted cash flow techniques and based on market assumptions as to the future commodity prices, internal estimates of future quantities of oil and natural gas reserves, future estimated rates of production, expected recovery rates and risk-adjustment discounts. The estimated fair values of unevaluated oil and natural gas properties were based on the location, engineering and geological studies, historical well performance, and applicable mineral lease terms. Given the unobservable nature of the inputs, the estimated fair values of oil and natural gas properties assumed is deemed to use Level 3 inputs. The asset retirement obligations assumed as part of business combinations are estimated using the same assumptions and methodology as described below.

The Company estimates asset retirement obligations pursuant to the provisions of the Financial Accounting Standards Board issued Accounting Standards Codification Topic 410, "Asset Retirement and Environmental Obligations". The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with the future plugging and abandonment of wells and related facilities. Given the unobservable nature of the inputs, including plugging costs and useful lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 7—Asset Retirement Obligations for further discussion of the Company's asset retirement obligations.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

	December 31, 2018			December 31, 2017		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Assets:						
Investment	$ 14,525	$ —	$ —	$ —	$ —	$ —

Fixed price swaps	$—	$215,335	$ —	$ —	$ —
Liabilities:					
Fixed price swaps	$—	$—	$ —	$(106,139)	$ —

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Notes to Consolidated Financial Statements-(Continued)

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, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$1,489,500	$1,489,500	$397,000	$397,000
4.625% Notes due 2021(1)	400,000	393,240	—	—
7.320% Medium-term Notes, Series A, due 2022(1)	20,000	20,780	—	—
4.750% Senior Notes due 2024	1,250,000	1,203,900	500,000	501,855
5.375% Senior Notes due 2025	800,000	782,000	500,000	515,000
7.350% Medium-term Notes, Series A, due 2027(1)	10,000	10,479	—	—
7.125% Medium-term Notes, Series B, due 2028(1)	100,000	102,329	—	—
Partnership revolving credit facility	411,000	411,000	93,500	93,500

(1) The Company assumed these notes (“Energen Notes”) in connection with the closing of the Energen Merger.

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

17. 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.

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, 2018:

Year Ending December 31,	Drilling Rig Commitments	Sand Supply Agreement	Office and Equipment Leases
	(in thousands)		
2019	$18,976	9,000	$ 9,019
2020	414	9,000	3,827
2021	—	9,000	1,452
2022	—	9,000	583

2023	—	2,250	—
Thereafter	—	—	—
Total	$19,390	$ 38,250	$ 14,881

The Company leases office space in Oklahoma City, Oklahoma from an unrelated third party. Amounts prior to January 1, 2018, include rent expense related to the Company’s corporate office located in the Fasken Center in Midland, Texas. On January 31, 2018, the Company completed its acquisition of the Fasken Center office buildings.

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

The following table presents rent expense for the years ended December 31, 2018, 2017 and 2016.

	Year ended December 31,		
	2018	2017	2016
	(in thousands)		
Rent Expense	$751	$2,412	$1,961

Drilling contracts

As of December 31, 2018, the Company had entered into drilling rig contracts with various third parties in the ordinary course of business to ensure rig availability to complete the Company’s drilling projects. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2018 total approximately $19.4 million.

Agreement with Trafigura Trading LLC

The Company has entered into a firm commitment oil purchase agreement with Trafigura Trading LLC (“Trafigura”), in which it agreed to sell and deliver an average of 25,000 barrels per day of Midland Sweet Crude Oil (WTI) to Trafigura during the term of the agreement. Under this agreement, which has a seven-year term beginning on August 1, 2018, the price per barrel of oil paid to the Company by Trafigura is based on the average of the published settlement quotations for NYMEX CMA, as adjusted for different delivery methods and periods. If during the term of the agreement the Company fails to deliver the required quantities of oil for any month other than for specified force majeure events, the Company has agreed to pay Trafigura a deficiency payment equal to any unfavorable difference between the contract price and the spot price, multiplied by the deficiency volume.

Agreement with Shell Trading (US) Company

The Company was a party to a five-year oil purchase agreement with Shell Trading (US) Company that expired on September 30, 2018. In December 2018, the Company entered into a new oil purchase agreement with Shell Trading (US) Company in which Shell Trading (US) Company agreed to transport crude petroleum it purchases from the Company over the Epic Crude Pipeline, with which the Company has an agreement for the transportation of a maximum quantity of 50,000 barrels of crude petroleum per day. The Company’s agreement with Shell Trading (US) Company provides for different purchase obligations during the pre-commencement and service commencement periods for the Epic Crude Pipeline, and provides for a three-year term beginning on the service commencement date for the Epic Crude Pipeline. Shell Trading (US) Company has the option to extend its purchase obligations for up to two one-year terms. The Company’s delivery obligations during the pre-commencement terms range from 30,000 to 40,000 barrels per day and, during the full service term, its maximum delivery obligation is 50,000 barrels per day, determined based on the amount of crude petroleum the Company is obligated to transport on the EPIC Crude Pipeline under its transportation agreement with such pipeline. During different pre-commencement periods, Shell Trading (US) Company has agreed to pay the Company 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, subject to agreed adjustments, or a specified price. During the full service term, the price per barrel of oil payable by Shell Trading (US) Company to the Company is subject to negotiation.

Agreement with Vitol Inc.

The Company has also entered into an oil purchase agreement with Vitol Inc. (“Vitol”). The agreement provides for different delivery obligations before and after the Gray Oak Pipeline is in full service, ranging from 23,750 barrels per day during the period from November 1, 2018 to September 30, 2019, to 50,000 barrels per day (up to a maximum of 100,000 barrels per day) once the Gray Oak Pipeline is in full service, determined based on the amount of crude petroleum the Company is obligated to transport on the Gray Oak Pipeline under its transportation agreement with such pipeline. The agreement with Vitol provides for a seven-year term commencing on the date when the Gray Oak Pipeline is in full service. The agreement contemplates variable prices depending on the delivery periods specified in the agreement. The agreement also provides for a five-year term commencing on the date the EPIC Crude Pipeline is ready to perform transportation services from the EPIC Midway Terminal, during which the Company agreed to sell crude petroleum to Vitol opportunistically at negotiated prices. If the Company fails to deliver any required quantities of oil for any month other than for specified force majeure events, it has agreed to pay Vitol a deficiency payment equal to any unfavorable difference between the contract price and the price paid by Vitol to third parties to replace the deficiency quantity, multiplied by the deficiency quantity, subject to certain other adjustments.

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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 immediately. For the years ended December 31, 2018, 2017 and 2016 the Company paid $2.1 million, $1.8 million and $1.2 million, respectively, in contributions to the plan.

18. SUBSEQUENT EVENTS

Commodity Contracts

Subsequent to December 31, 2018, the Company entered into new fixed price swaps. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing.

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Notes to Consolidated Financial Statements-(Continued)

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

	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
January 2019 - December 2019		
Oil Swaps - WTI Magellan East Houston	368,000	$ 59.15
Oil Swaps - BRENT	275,000	$ 61.90
Oil Basis Swaps - WTI Cushing	182,000	$ (4.15)
Oil Basis Swaps - WTI Midland	364,000	$ (2.68)
Natural Gas Swaps - Waha Hub	6,680,000	$ (1.47)

	January 2019 - June 2019	January 2020 - June 2020
Oil Three-Way Collars	Brent	Brent
Volume (Bbls)	368,000	732,000
Short put price (per Bbl)	$ 50.00	$ 50.00
Floor price (per Bbl)	$ 60.00	$ 60.00
Ceiling price (per Bbl)	$ 69.43	$ 73.90

On February 1, 2019, Rattler LLC obtained a 10% equity interest in the EPIC Crude Pipeline Project, which, once operational, will transport crude oil and NGL across Texas for delivery into the Corpus Christi market. As of February 19, 2019, Rattler LLC has invested $34.1 million in the EPIC project and recorded no income. The EPIC project is anticipated to be operational in the second half of 2019.

On February 15, 2019, Rattler LLC obtained a 10% equity interest in the Gray Oak Pipeline Project, which, once operational, will transport crude oil from the Permian Basin to Corpus Christi on the Texas Gulf Coast. As of February 19, 2019, Rattler LLC has invested $81.3 million in the Gray Oak project and recorded no income. The Gray Oak project is anticipated to be operational in the second half of 2019.

19. GUARANTOR FINANCIAL STATEMENTS

As of December 31, 2018, Diamondback E&P LLC, Diamondback O&G LLC and Energen Corporation and its subsidiaries (the “Guarantor Subsidiaries”) are guarantors under the indentures relating to the 2024 Senior Notes and the 2025 Senior Notes, as supplemented. In connection with the issuance of the 2024 Senior Notes and the 2025 Senior Notes, the Partnership, the General Partner, Viper Energy Partners LLC and Rattler Midstream Operating LLC were designated as Non-Guarantor Subsidiaries. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 19 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, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$83,791	$108,049	$22,676	$—	$214,516
Accounts receivable, net	—	353,238	38,823	—	392,061
Accounts receivable - related party	—	—	3,489	(3,489)	—
Intercompany receivable	4,468,813	200,795	—	(4,669,608)	—
Inventories	—	37,570	—	—	37,570
Other current assets	2,583	278,034	257	—	280,874
Total current assets	4,555,187	977,686	65,245	(4,673,097)	925,021
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	20,585,766	1,716,713	(3,297)	22,299,182
Midstream assets	—	700,295	—	—	700,295
Other property, equipment and land	—	141,275	5,688	—	146,963
Accumulated depletion, depreciation, amortization and impairment	—	(2,513,893)	(248,296)	(12,276)	(2,774,465)
Net property and equipment	—	18,913,443	1,474,105	(15,573)	20,371,975
Investment in subsidiaries	11,575,513	112,434	—	(11,687,947)	—
Investment in real estate, net	—	115,625	—	—	115,625
Deferred tax asset	(213)	—	96,883	—	96,670
Other assets	344	68,221	17,831	—	86,396
Total assets	$16,130,831	$20,187,409	$1,654,064	$(16,376,617)	$21,595,687
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$127,979	$—	$—	$127,979
Intercompany payable	—	4,673,097	—	(4,673,097)	—
Other current liabilities	14,292	871,319	6,022	—	891,633
Total current liabilities	14,292	5,672,395	6,022	(4,673,097)	1,019,612
Long-term debt	2,035,554	2,017,784	411,000	—	4,464,338
Derivative instruments	—	15,192	—	—	15,192
Asset retirement obligations	—	136,181	—	—	136,181
Deferred income taxes	381,698	1,402,834	—	—	1,784,532
Other long-term liabilities	—	9,570	—	—	9,570
Total liabilities	2,431,544	9,253,956	417,022	(4,673,097)	7,429,425
Commitments and contingencies					
Stockholders' equity	13,699,287	10,933,453	542,102	(11,475,555)	13,699,287
Non-controlling interest	—	—	694,940	(227,965)	466,975
Total equity	13,699,287	10,933,453	1,237,042	(11,703,520)	14,166,262
Total liabilities and equity	$16,130,831	$20,187,409	$1,654,064	$(16,376,617)	$21,595,687

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

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

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

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$1,631,703	$—	$246,922	$1,878,625
Natural gas sales	—	48,070	—	12,976	61,046
Natural gas liquid sales	—	167,346	—	22,763	190,109
Royalty income	—	—	282,661	(282,661)	—
Lease bonus	—	—	6,029	(3,109)	2,920
Midstream services	—	34,254	—	—	34,254
Other operating income	—	9,172	130	—	9,302
Total revenues	—	1,890,545	288,820	(3,109)	2,176,256
Costs and expenses:					
Lease operating expenses	—	204,975	—	—	204,975
Production and ad valorem taxes	—	113,613	19,048	—	132,661
Gathering and transportation	—	26,113	—	—	26,113
Midstream services	—	71,878	—	—	71,878
Depreciation, depletion and amortization	—	547,592	58,830	16,617	623,039
General and administrative expenses	28,490	30,569	7,955	(2,460)	64,554
Merger & integration	18,476	18,355	—	—	36,831
Asset retirement obligation accretion	—	2,132	—	—	2,132
Other operating expense	—	3,285	—	—	3,285
Total costs and expenses	46,966	1,018,512	85,833	14,157	1,165,468
Income (loss) from operations	(46,966)	872,033	202,987	(17,266)	1,010,788
Other income (expense)					
Interest expense, net	(43,482)	(29,945)	(13,849)	—	(87,276)
Other income (expense), net	1,463	88,069	1,924	(2,460)	88,996
Loss on derivative instruments, net	—	101,299	—	—	101,299
Gain on revaluation of investment	—	—	(550)	—	(550)
Total other income (expense), net	(42,019)	159,423	(12,475)	(2,460)	102,469
Income (loss) before income taxes	(88,985)	1,031,456	190,512	(19,726)	1,113,257
Provision for (benefit from) income taxes	240,727	—	(72,365)	—	168,362
Net income (loss)	(329,712)	1,031,456	262,877	(19,726)	944,895
Net income attributable to non-controlling interest	—	—	118,919	(19,696)	99,223
Net income (loss) attributable to Diamondback Energy, Inc.	$(329,712)	$1,031,456	$143,958	$(30)	$845,672

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$ 903,842	$ —	$ 140,175	$ 1,044,017
Natural gas sales	—	42,899	—	9,311	52,210
Natural gas liquid sales	—	79,371	—	10,677	90,048
Royalty income	—	—	160,163	(160,163)	—
Lease bonus	—	—	11,870	(106)	11,764
Midstream services	—	7,072	—	—	7,072
Total revenues	—	1,033,184	172,033	(106)	1,205,111
Costs and expenses:					
Lease operating expenses	—	126,524	—	—	126,524
Production and ad valorem taxes	—	62,897	10,608	—	73,505
Gathering and transportation	—	12,045	789	—	12,834
Midstream services	—	10,409	—	—	10,409
Depreciation, depletion and amortization	—	281,989	40,519	4,251	326,759
General and administrative expenses	26,776	18,057	6,296	(2,460)	48,669
Asset retirement obligation accretion	—	1,391	—	—	1,391
Total costs and expenses	26,776	513,312	58,212	1,791	600,091
Income (loss) from operations	(26,776)	519,872	113,821	(1,897)	605,020
Other income (expense)					
Interest expense, net	(29,925)	(7,465)	(3,164)	—	(40,554)
Other income (expense), net	1,142	10,732	821	(2,460)	10,235
Loss on derivative instruments, net	—	(77,512)	—	—	(77,512)
Total other expense, net	(28,783)	(74,245)	(2,343)	(2,460)	(107,831)
Income (loss) before income taxes	(55,559)	445,627	111,478	(4,357)	497,189
Benefit from income taxes	(19,568)	—	—	—	(19,568)
Net income (loss)	(35,991)	445,627	111,478	(4,357)	516,757
Net income attributable to non-controlling interest	—	—	—	34,496	34,496
Net income (loss) attributable to Diamondback Energy, Inc.	$ (35,991)	$ 445,627	$ 111,478	$ (38,853)	$ 482,261

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$ 399,007	$ —	$ 71,521	$ 470,528
Natural gas sales	—	19,399	—	3,107	22,506
Natural gas liquid sales	—	29,864	—	4,209	34,073
Royalty income	—	—	78,837	(78,837)	—
Lease bonus income	—	—	309	(309)	—
Total revenues	—	448,270	79,146	(309)	527,107
Costs and expenses:					
Lease operating expenses	—	82,428	—	—	82,428
Production and ad valorem taxes	—	28,912	5,544	—	34,456
Gathering and transportation	—	11,189	415	2	11,606
Depreciation, depletion and amortization	—	151,376	29,820	(3,181)	178,015
Impairment of oil and natural gas properties	—	198,067	47,469	—	245,536
General and administrative expenses	25,959	11,451	5,209	—	42,619
Asset retirement obligation accretion expense	—	1,064	—	—	1,064
Total costs and expenses	25,959	484,487	88,457	(3,179)	595,724
Income (loss) from operations	(25,959)	(36,217)	(9,311)	2,870	(68,617)
Other income (expense)					
Interest expense, net	(35,318)	(2,911)	(2,455)	—	(40,684)
Other income, net	437	2,010	867	(250)	3,064
Loss on derivative instruments, net	—	(25,345)	—	—	(25,345)
Loss on extinguishment of debt	(33,134)	—	—	—	(33,134)
Total other expense, net	(68,015)	(26,246)	(1,588)	(250)	(96,099)
Income (loss) before income taxes	(93,974)	(62,463)	(10,899)	2,620	(164,716)
Provision for income taxes	192	—	—	—	192
Net income (loss)	$(94,166)	$ (62,463)	$ (10,899)	$ 2,620	$ (164,908)
Net income attributable to non-controlling interest	$—	$ —	$ —	$ 126	$ 126
Net income (loss) attributable to Diamondback Energy, Inc.	$(94,166)	$ (62,463)	$ (10,899)	$ 2,494	$ (165,034)

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

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$(57,960)	$1,377,972	$244,493	$ —	$1,564,505
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(1,460,509)	—	—	(1,460,509)
Additions to midstream assets	—	(204,222)	—	—	(204,222)
Purchase of other property, equipment and land	—	(2,153)	(4,687)	—	(6,840)
Acquisition of leasehold interests	—	(1,370,951)	—	—	(1,370,951)
Acquisition of mineral interests	—	169,828	(610,131)	—	(440,303)
Proceeds from sale of assets	—	79,533	565	—	80,098
Funds held in escrow	—	10,989	—	—	10,989
Purchase of other investments	—	(8)	—	—	(8)
Equity investments	—	(612)	—	—	(612)
Intercompany transfers	(366,634)	366,634	—	—	—
Investment in real estate	—	(110,685)	—	—	(110,685)
Net cash used in investing activities	(366,634)	(2,522,156)	(614,253)	—	(3,503,043)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	1,960,000	691,500	—	2,651,500
Repayment under credit facility	—	(867,500)	(374,000)	—	(1,241,500)
Repayment of Energen credit facility	—	(559,000)	—	—	(559,000)
Proceeds from senior notes	1,062,000	—	—	—	1,062,000
Debt issuance costs	(13,926)	(10,496)	(1,039)	—	(25,461)
Public offering costs	—	—	(2,652)	—	(2,652)
Proceeds from public offerings	—	—	305,773	—	305,773
Contributions to subsidiaries	(1,000)	—	(1,000)	2,000	—
Contributions by members	—	—	2,000	(2,000)	—
Distributions from subsidiary	155,138	—	—	(155,138)	—
Unit options exercised	—	—	140	—	140
Repurchased for tax withholdings	(14,460)	—	—	—	(14,460)
Dividends to stockholders	(37,313)	—	—	—	(37,313)
Other postemployment benefit changes	—	(74)	—	—	(74)
Distributions to non-controlling interest	—	—	(253,483)	155,138	(98,345)
Intercompany transfers	(696,128)	695,128	1,000	—	—
Net cash provided by financing activities	454,311	1,218,058	368,239	—	2,040,608
Net increase (decrease) in cash and cash equivalents	29,717	73,874	(1,521)	—	102,070
Cash and cash equivalents at beginning of period	54,074	34,175	24,197	—	112,446
Cash and cash equivalents at end of period	$83,791	$108,049	$22,676	$ —	$214,516

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

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (29,470)	$ 778,876	$ 139,219	$ —	$ 888,625
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(792,599)	—	—	(792,599)
Additions to midstream assets	—	(68,139)	—	—	(68,139)
Purchase of other property, equipment and land	—	(22,779)	—	—	(22,779)
Acquisition of leasehold interests	—	(1,960,591)	—	—	(1,960,591)
Acquisition of mineral interests	—	(63,371)	(344,079)	—	(407,450)
Acquisition of midstream assets	—	(50,279)	—	—	(50,279)
Proceeds from sale of assets	—	65,656	—	—	65,656
Funds held in escrow	—	104,087	—	—	104,087
Equity investments	—	(188)	—	—	(188)
Intercompany transfers	(1,631,078)	1,631,078	—	—	—
Net cash used in investing activities	(1,631,078)	(1,157,125)	(344,079)	—	(3,132,282)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	475,000	278,500	—	753,500
Repayment under credit facility	—	(78,000)	(305,500)	—	(383,500)
Purchase of subsidiary units by parent	(10,068)	—	—	10,068	—
Debt issuance costs	(8,326)	1,289	(2,259)	—	(9,296)
Public offering costs	(77)	—	(433)	—	(510)
Proceeds from public offerings	—	—	380,412	(10,068)	370,344
Distributions from subsidiary	89,509	—	—	(89,509)	—
Exercise of stock options	358	—	—	—	358
Distributions to non-controlling interest	—	—	(130,876)	89,509	(41,367)
Net cash provided by financing activities	71,396	398,289	219,844	—	689,529
Net increase (decrease) in cash and cash equivalents	(1,589,152)	20,040	14,984	—	(1,554,128)
Cash and cash equivalents at beginning of period	1,643,226	14,135	9,213	—	1,666,574
Cash and cash equivalents at end of period	$ 54,074	$ 34,175	$ 24,197	$ —	$ 112,446

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

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$(39,894)	$303,347	$68,627	$—	$332,080
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(363,087)	—	—	(363,087)
Additions to midstream assets	—	(1,188)	—	—	(1,188)
Purchase of other property, equipment and land	—	(9,891)	—	—	(9,891)
Acquisition of leasehold interests	—	(611,280)	—	—	(611,280)
Acquisition of mineral interests	—	—	(205,721)	—	(205,721)
Proceeds from sale of assets	—	4,661	—	—	4,661
Funds held in escrow	—	(121,391)	—	—	(121,391)
Equity investments	—	(2,345)	—	—	(2,345)
Intercompany transfers	(796,053)	796,053	—	—	—
Net cash used in investing activities	(796,053)	(308,468)	(205,721)	—	(1,310,242)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	—	164,000	—	164,000
Repayment under credit facility	—	(11,000)	(78,000)	—	(89,000)
Proceeds from senior notes	1,000,000	—	—	—	1,000,000
Repayment of senior notes	(450,000)	—	—	—	(450,000)
Premium on extinguishment of debt	(26,561)	—	—	—	(26,561)
Debt issuance costs	(14,449)	(172)	(442)	—	(15,063)
Public offering costs	(636)	—	(546)	—	(1,182)
Proceeds from public offerings	1,925,923	—	125,580	—	2,051,503
Distribution from subsidiary	55,250	—	—	(55,250)	—
Exercise of stock options	498	—	—	—	498
Distribution to non-controlling interest	—	—	(64,824)	55,250	(9,574)
Intercompany transfers	(11,000)	11,000	—	—	—
Net cash provided by (used in) financing activities	2,479,025	(172)	145,768	—	2,624,621
Net increase (decrease) in cash and cash equivalents	1,643,078	(5,293)	8,674	—	1,646,459
Cash and cash equivalents at beginning of period	148	19,428	539	—	20,115
Cash and cash equivalents at end of period	$1,643,226	$14,135	$9,213	$—	$1,666,574

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

20. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company’s oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	December 31,	
	2018	2017
	(In thousands)	
Oil and natural gas properties:		
Proved properties	$12,629,205	$5,126,829
Unproved properties	9,669,977	4,105,865
Total oil and natural gas properties	22,299,182	9,232,694
Accumulated depreciation, depletion, amortization	(1,599,111)	(1,009,893)
Accumulated impairment	(1,143,498)	(1,143,498)
Net oil and natural gas properties capitalized	$19,556,573	$7,079,303

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Acquisition costs:			
Proved properties	$5,551,400	$452,661	$72,044
Unproved properties	5,818,006	2,692,000	752,117
Development costs	493,084	145,362	47,575
Exploration costs	1,090,281	779,728	329,122
Capitalized asset retirement costs	113,717	2,682	4,030
Total	$13,066,488	$4,072,433	$1,204,888

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

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and natural gas liquids operations.

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Oil, natural gas and natural gas liquid sales	$2,129,780	$1,186,275	$527,107
Lease operating expenses	(204,975)	(126,524)	(82,428)
Production and ad valorem taxes	(132,661)	(73,505)	(34,456)
Gathering and transportation	(26,113)	(12,834)	(11,606)
Depreciation, depletion, and amortization	(594,750)	(321,870)	(176,369)
Impairment	—	—	(245,536)
Asset retirement obligation accretion expense	(2,132)	(1,391)	(1,064)
Income tax benefit (expense)	(241,149)	19,568	(192)
Results of operations	$928,000	$669,719	$(24,544)

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2018, 2017 and 2016 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

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.

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The changes in estimated proved reserves are as follows:

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves:			
As of January 1, 2016	105,979	26,004	149,503
Extensions and discoveries	55,069	13,962	64,758
Revisions of previous estimates	(12,483)	(1,888)	(34,519)
Purchase of reserves in place	2,537	1,455	7,567
Divestitures	(366)	—	(1,985)
Production	(11,562)	(2,399)	(10,428)
As of December 31, 2016	139,174	37,134	174,896
Extensions and discoveries	99,980	20,825	109,032
Revisions of previous estimates	(7,715)	(1,466)	(10,065)
Purchase of reserves in place	24,322	2,633	34,640
Divestitures	(1,163)	(461)	(2,474)
Production	(21,417)	(4,056)	(20,660)
As of December 31, 2017	233,181	54,609	285,369
Extensions and discoveries	143,256	33,152	154,088
Revisions of previous estimates	3,689	11,138	3,642
Purchase of reserves in place	281,333	98,865	640,761
Divestitures	(156)	(8)	(543)
Production	(34,367)	(7,465)	(34,668)
As of December 31, 2018	626,936	190,291	1,048,649
Proved Developed Reserves:			
January 1, 2016	60,569	15,418	96,871
December 31, 2016	79,457	22,080	105,399
December 31, 2017	141,246	35,412	190,740
December 31, 2018	403,051	125,509	705,084
Proved Undeveloped Reserves:			
January 1, 2016	45,409	10,586	52,632
December 31, 2016	59,717	15,054	69,497
December 31, 2017	91,935	19,198	94,629
December 31, 2018	223,885	64,782	343,565

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2018, the Company’s extensions and discoveries of 202,089 MBOE resulted primarily from the drilling of 135 new wells and from 138 new proved undeveloped locations added in which the Company owns a working interest. Partnership royalty interests accounted for 10% of the extension volumes. The

Company's revisions of previous estimates were primarily the result of positive technical and performance revisions of 14,218 MBOE, upward revisions of 6,032 MBOE due to higher pricing and downward revisions of 4,815 MBOE from PUD reclassifications due to timing. Purchases of 486,992 MBOE were the result of 477,686 of working interest purchases, primarily attributable to Energen, and 9,306 MBOE of Partnership royalty purchases.

During the year ended December 31, 2017, the Company's extensions and discoveries of 138,977 MBOE resulted primarily from the drilling of 102 new wells and from 87 new proved undeveloped locations added. Partnership royalty interests

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accounted for 8% of the extension volumes. The Company's revisions of previous estimates were primarily the result of 2,550 MBOE from reclassifying PUD locations due to anticipated timing, with the remaining 8,308 MBOE being technical revisions. Delaware Basin working interest purchases accounted for 87% of the total purchases and Partnership royalty interest purchases accounted for 10%, with working interest purchases contributing the remainder.

During the year ended December 31, 2016, the Company's extensions and discoveries of 69,042 MBOE resulted primarily from the drilling of 59 new wells and from 51 new proved undeveloped locations added. The Company owns the mineral interests associated with 30 of the 59 new wells and 30 of the 51 proved undeveloped locations through the Partnership. The Company's negative revisions of previous estimates were primarily the result of 5,978 MBOE of pricing revisions and 7,253 MBOE from reclassifying 17 locations from proved undeveloped due to pricing. Purchases of reserves in place of 3,993 MBOE were primarily the result of the purchase of producing wells included with the Reeves and Ward county acreage purchase and reserves associated with multiple purchases made by the Partnership.

At December 31, 2018, the Company's estimated PUD reserves were approximately 345,928 MBOE, a 219,023 MBOE increase over the reserve estimate at December 31, 2017 of 126,905 MBOE. The following table includes the changes in PUD reserves for 2018:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2017	126,905
Undeveloped reserves transferred to developed	(71,435)
Revisions	338
Net purchases	165,426
Extensions and discoveries	124,694
Ending proved undeveloped reserves at December 31, 2018	345,928

The increase in proved undeveloped reserves was primarily attributable to purchases of 165,426 MBOE mostly from the acquisition of Energen. Extensions contributed 111,020 MBOE from 138 gross (122 net) wells in which the Company has a working interest and 13,674 MBOE from 138 gross wells in which the Partnership owns royalty interests. Of the 138 gross working interest wells, 38 were in the Delaware Basin. Transfers of 71,435 MBOE were the result of drilling or participating in 89 gross (79 net) horizontal wells in which the Company has a working interest and 49 gross wells in which the Company has a royalty interest or mineral interest through the Partnership. The Company owns a working interest in 45 of the 49 gross Partnership wells. Upward revisions of 338 MBOE resulted from commodity price improvement and type curve performance.

As of December 31, 2018, all of the Company's proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2018, approximately $493.1 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

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The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves as of December 31, 2018, 2017 and 2016.

	December 31,		
	2018	2017	2016
	(In thousands)		
Future cash inflows	$43,578,469	$12,921,897	$6,275,705
Future development costs	(3,560,142)	(1,123,979)	(617,636)
Future production costs	(7,727,257)	(2,994,877)	(1,392,852)
Future production taxes	(2,934,521)	(928,891)	(459,244)
Future income tax expenses	(3,913,024)	(83,961)	(75,595)
Future net cash flows	25,443,525	7,790,189	3,730,378
10% discount to reflect timing of cash flows	(13,767,064)	(4,033,130)	(2,018,965)
Standardized measure of discounted future net cash flows	$11,676,461	$3,757,059	$1,711,413

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows.

	December 31,		
	2018	2017	2016
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$59.63	$48.03	$39.94
Natural gas (per Mcf)	$1.47	$2.06	$1.36
Natural gas liquids (per Bbl)	$24.43	$20.79	$12.91

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$3,757,059	$1,711,413	$1,418,133
Sales of oil and natural gas, net of production costs	(1,786,106)	(986,246)	(411,558)
Acquisition of reserves	5,520,438	439,396	43,142
Divestiture of reserves	(2,036)	(11,072)	(5,481)
Extensions and discoveries, net of future development costs	3,287,043	1,791,686	779,359
Previously estimated development costs incurred during the period	534,768	190,121	85,696
Net changes in prices and production costs	1,805,428	577,781	(150,509)
Changes in estimated future development costs	(81,062)	(52,908)	20,647
Revisions of previous quantity estimates	270,959	(98,857)	(123,795)
Accretion of discount	379,659	174,185	143,134
Net change in income taxes	(1,727,907)	(9,074)	(30,530)
Net changes in timing of production and other	(281,782)	30,634	(56,825)
	$11,676,461	$3,757,059	$1,711,413

Standardized measure of discounted future net cash flows at the end of the period

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

21. QUARTERLY FINANCIAL DATA (Unaudited)

The Company's unaudited quarterly financial data for 2018 and 2017 is summarized below.

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$480,195	$526,273	$538,029	$631,759
Income from operations	267,646	281,303	266,851	194,988
Income tax expense (benefit)	47,081	(6,607)	42,276	85,612
Net income	178,154	301,164	159,417	306,160
Net income (loss) attributable to non-controlling interest	15,342	82,018	2,363	(500)
Net income attributable to Diamondback Energy, Inc.	$162,812	$219,146	$157,054	$306,660
Earnings per common share				
Basic	$1.65	$2.22	$1.59	$2.50
Diluted	$1.65	$2.22	$1.59	$2.50

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$235,230	$269,434	$301,253	$399,194
Income from operations	116,410	132,308	142,639	213,663
Income tax expense (benefit)	1,957	1,579	857	(23,961)
Net income	141,074	164,128	81,948	129,607
Net income attributable to non-controlling interest	4,801	5,723	8,924	15,048
Net income attributable to Diamondback Energy, Inc.	$136,273	$158,405	$73,024	$114,559
Earnings per common share				
Basic	$1.46	$1.61	$0.74	$1.17
Diluted	$1.46	$1.61	$0.74	$1.16