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

FORM 10-K

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

For the fiscal year ended December 31, 2019

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)

DE	**45-4502447**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas **Suite 1200** **Midland, TX**	**79701**
(Address of principal executive offices)	**(Zip code)**

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

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

Title of Each Class	**Trading Symbol(s)**	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	FANG	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

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 ☒ 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 ☒

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 ☒ 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 ☒ No ☐

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	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

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. ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 28, 2019 was approximately $15.9 billion.

As of February 14, 2020, 158,284,486 shares of the registrant’s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.’s Proxy Statement for the 2020 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K

DIAMONDBACK ENERGY, INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2019

TABLE OF CONTENTS

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.
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.
WTI MEH	West Texas Intermediate Magellan East Houston.
WTL	West Texas Light

GLOSSARY OF CERTAIN OTHER TERMS

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

ASU	Accounting Standards Update
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173).
EPA	U.S. Environmental Protection Agency.
Equity Plan	The Company's Equity Incentive Plan.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
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.
December 2019 Notes Indenture	The indenture relating to the December 2019 Notes dated as of December 5, 2019, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
OSHA	Federal Occupational Safety and Health Act.
Rattler	Rattler Midstream LP, a Delaware limited partnership.
Rattler's general partner	Rattler Midstream GP LLC, a Delaware limited liability company; the general partner of Rattler Midstream LP and a wholly-owned subsidiary of the Company.
Rattler LLC	Rattler Midstream Operating LLC, a Delaware limited liability company and a subsidiary of Rattler.
Rattler LTIP	Rattler Midstream LP Long-Term Incentive Plan.
Rattler Offering	Rattler's initial public offering.
Rattler's Partnership Agreement	The first amended and restated agreement of limited partnership, dated May 28, 2019.
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, the 2025 Senior Notes and the Series of Senior Notes
December 2019 Notes	The Company's 2.875% senior unsecured notes due 2024 in the aggregate principal amount of $1.0 billion, the Company's 3.250% senior unsecured notes due 2026 in the aggregate principal amount of $800 million and the Company's 3.500% senior unsecured notes due 2029 in the aggregate principal amount of $1.2 billion.
Viper	Viper Energy Partners LP, a Delaware limited partnership.
Viper's general partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Viper LLC	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of the Partnership.
Viper LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Viper Offering	Viper's initial public offering.
Viper's Partnership Agreement	The second amended and restated agreement of limited partnership, dated May 9, 2018, as amended as of May 10, 2018.
Wells Fargo	Wells Fargo Bank, National Association.
Wexford	Wexford Capital LP

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 intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report on Form 10–K, including under *Part I, Item 1A.* “Risk Factors” in this report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- competition in the oil and natural gas industry;
- acquisitions;
- our recently completed drop-down transaction with our subsidiary Viper Energy Partners LP, or Viper;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices and effects of hedging arrangements;
- levels of production;
- the impact of reduced drilling activity;
- regional supply and demand factors, delays or interruptions of production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results;
- conditions in the capital markets and our ability to obtain capital on favorable terms or at all;
- general economic business or industry conditions;
- capital expenditure plans; and
- other 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, 2019, our total acreage position in the Permian Basin was approximately 455,378 gross (382,337 net) acres, which consisted primarily of approximately 218,138 gross (195,461 net) acres in the Midland Basin and approximately 196,171 gross (155,296 net) acres in the Delaware Basin. In addition, our publicly traded subsidiary Viper Energy Partners LP, which we refer to as Viper, owns mineral interests underlying approximately 814,224 gross acres and 24,304 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 50% 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 Viper's general partner, and we own approximately 58% of the limited partner interest in Viper. Further, our publicly traded subsidiary Rattler Midstream Partners LP, which we refer to as Rattler, is focused on ownership, operation, development and acquisition of midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. We own Rattler Midstream GP LLC, the general partner of Rattler, which we refer to as Rattler's general partner, and we own approximately 71% of the limited partner interest in Rattler. As of December 31, 2019, Rattler owned and operated 867 miles of crude oil gathering pipelines, natural gas gathering pipelines and a fully integrated water system on acreage that overlays our seven core Midland and Delaware Basin development areas. To facilitate the transportation of produced water and hydrocarbon volumes away from the producing wellhead to ensuring the efficient operations of a crude oil or natural gas well, Rattler's midstream infrastructure includes a network of gathering pipelines that collect and transport crude oil, natural gas and produced water from our operations in the Midland and Delaware Basins.

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, 2019, our estimated proved oil and natural gas reserves were 1,127,575 MBOE (which includes estimated reserves of 88,946 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 67% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 477 gross (434 net) horizontal well locations in which we have a working interest, and 22 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2019, our estimated proved reserves were approximately 63% oil, 20% natural gas liquids and 17% natural gas.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 12,310 gross (8,141 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.

Significant 2019 Transactions

Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

On May 23, 2019, we completed our divestiture of 6,589 net acres of certain non-core Permian assets, which we acquired in our November 2018 merger with Energen Corporation, which we refer to as the Energen merger, for an aggregate sale price of $37 million.

On July 1, 2019, we completed our divestiture of 103,750 net acres of certain conventional and non-core Permian assets, which we acquired in the Energen merger, for an aggregate sale price of $285 million.

Drop-Down

On October 1, 2019, we completed a transaction to divest certain mineral and royalty interests to Viper for approximately 18.3 million of Viper's newly-issued Class B units, approximately 18.3 million newly-issued units of Viper LLC with a fair value of $497 million and $190 million in cash, after giving effect to closing adjustments for net title benefits, which we refer to as the Drop-Down. The mineral and royalty interests divested in the Drop-Down represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by us, and have an average net royalty interest of approximately 3.2%.

Rattler's Initial Public Offering

In May 2019, Rattler completed its initial public offering, which we refer to as the Rattler Offering, of an aggregate 43,700,000 common units at a price to the public of $17.50 per share, which common units are traded on the Nasdaq Global Select Market under the symbol "RTLR." Rattler received aggregate net proceeds of approximately $720 million from the sale of these common units, after deducting the underwriting discount and offering expenses.

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. 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. The following table presents horizontal wells in which we have an interest in as of December 31, 2019:

Basin	Number of Horizontal Wells
Midland	1,125
Delaware	645
Total[(1)]	1,770

(1) Of these 1,770 total horizontal wells, we are the operator of 1,489 producing wells and have a non-operated working interest in 281 additional wells.

The following table presents the average number of days in which we were able to drill our horizontal wells to total depth specified below during the year ended December 31, 2019:

	Average Days to Total Depth
Midland Basin	
7,500 foot lateral	14
10,000 foot lateral	15
13,000 foot lateral	17
Delaware Basin	
7,500 foot lateral	20
10,000 foot lateral	25
13,000 foot lateral	27

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 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 97% 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 84% 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.

- **Maintain financial flexibility.** We seek to maintain a conservative financial position. As of December 31, 2019, our borrowing base was set at $2.0 billion and we had $1.99 billion available for borrowing. As of December 31, 2019, Viper LLC had $97 million in outstanding borrowings, and $678 million available for borrowing, under its revolving credit facility. As of December 31, 2019, Rattler LLC had $424 million in outstanding borrowings, and $176 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, 2019 was approximately 66% oil, 18% natural gas liquids and 16% natural gas. As of December 31, 2019, our estimated net proved reserves were comprised of approximately 63% oil, 20% natural gas liquids and 17% 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 12,310 gross (8,141 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 7,975 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. 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 3,413 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.

The following table presents the number of identified economic potential horizontal drilling locations by basin:

	Number of Identified Economic Potential Horizontal Drilling Locations
Midland Basin	
Lower Spraberry(1)	1,231
Middle Spraberry(2)	1,151
Wolfcamp A(3)	1,205
Wolfcamp B(4)	1,213
Other	2,237
Total Midland Basin	7,037
Delaware Basin	
2nd Bone Springs(5)	957
3rd Bone Springs(5)	1,177
Wolfcamp A(6)	944
Wolfcamp B(6)	1,050
Other	1,145
Total Delaware Basin	5,273
Total	12,310

(1) Our current location count 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.
(2) Our current location count is based on 660 foot spacing in Midland, Martin and northeast Andrews counties, depending on the prospect area and 880 foot spacing in all other counties.
(3) Our current location count 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.
(4) Our current location count in 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.
(5) Our current location count is based on 880 foot to 1,320 foot spacing.
(6) Our current location count is based on 880 foot to 1,056 foot spacing.

- **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 97% 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.

- **Access to Midstream Infrastructure and Gathering and Transportation Pipelines**. Through our publicly traded subsidiary Rattler, we have secured access to midstream infrastructure and crude oil gathering and transportation pipelines tailored to our expected production growth ramp in order to allow us the operational flexibility to execute on our growth plan. Rattler is the primary provider of midstream services to us with an acreage dedication that spans a total of approximately 397,000 gross acres across all of Rattler’s service lines and over the core of the Midland and Delaware Basins.

Our Properties

Location and Land

Our total acreage position in the Permian Basin was approximately 455,378 gross (382,337 net) acres, which consisted primarily of approximately 218,138 gross (195,461 net) acres in the Midland Basin and approximately 196,171 gross (155,296 net) acres in the Delaware Basin at December 31, 2019. We are the operator of approximately 97% of this Permian Basin acreage. In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 814,224 gross acres and 24,304 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 50% of these net royalty acres are operated by us.

Further, our subsidiary Rattler is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. As of December 31, 2019, Rattler owned and operated 867 miles of crude oil gathering pipelines, natural gas gathering pipelines and a fully integrated water system on acreage that overlays our seven core Midland and Delaware Basin development areas. To facilitate the transportation of water and hydrocarbon volumes away from the producing wellhead to ensuring the efficient operations of a crude oil or natural gas well, Rattler’s midstream infrastructure includes a network of gathering pipelines that collect and transport crude oil, natural gas and produced water from our operations in the Midland and Delaware Basins.

As of December 31, 2019, Rattler also owned (i) a 10% equity interest in EPIC Crude Holdings LP, which is building a long-haul crude oil pipeline from the Permian Basin and the Eagle Ford Shale to Corpus Christi, Texas that, upon completion, will be capable of transporting approximately 590,000 Bbl/d and, with installation of additional pumps and storage, up to approximately 900,000 Bbl/d, which we refer to as the EPIC pipeline; (ii) a 10% equity interest in Gray Oak Pipeline, LLC, which is building a long-haul crude oil pipeline that, upon completion, will be capable for transporting 900,000 Bbl/d from the Permian Basin and the Eagle Ford Shale to points alongside the Texas Gulf Coast, including a marine terminal connection in Corpus Christi, Texas, which we refer to as the Gray Oak pipeline; (iii) a 4% equity interest in Wink to Webster Pipeline LLC, which is developing a crude oil pipeline that, upon completion, will be capable of transporting approximately 1,000,000 Bbl/d from origin points at Wink and Midland in the Permian Basin for delivery to multiple Houston area locations, (iv) a 60% equity interest in OMOG JV LLC, a newly formed joint venture entity that acquired Reliance Midstream LLC, which operates over 230 miles of crude oil gathering and regional transportation pipelines and approximately 200,000 barrels of crude oil storage in Midland, Martin, Andrews and Ector Counties, Texas, and (v) a 50% equity interest in Amarillo Rattler LLC, which will operate the Yellow Rose gas gathering and processing system with estimated total capacity of 40,000 Mcf/d and over 84 miles of gathering and regional transportation pipelines in Dawson, Martin and Andrews Counties, Texas. Each of the Epic and Gray Oak pipelines began interim operations in the second half of 2019, and we expect both to begin full commercial operations in the second quarter of 2020. The Wink to Webster project is expected to begin commercial operations in first half of 2021. We anticipate that the Yellow Rose system will commence full commercial operations in the middle of 2021.

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, 2019, we held working interests in 2,656 gross (2,202 net) producing wells and only royalty interests in 4,161 additional wells.

Geology

The Greater Permian Basin formed as an area of rapid Pennsylvanian-Permian subsidence in response to dynamic structural influence of the Marathon Uplift and Ancestral Rockies. It is one of the most productive sedimentary basins in the U.S., with established oil and gas production from several stacked reservoirs of varying age ranges, most notably Permian aged sediments. In particular, the Permian aged Wolfcamp and Spraberry/Bone Spring Formations have been heavily targeted for several decades. First, through vertical comingling of these zones and, more recently, through horizontal exploitation of each individual horizon. Prior to deposition of Wolfcamp and Spraberry/Bone Spring Formations, the area of the present-day Permian Basin was a continuous sedimentary feature called the Tabosa Basin. During this time, Ordovician, Silurian, Devonian and Mississippian sediments were laid down in a primarily open marine, shelf setting. However, some time frames saw more restrictive settings that were conducive to the deposition of organically rich mudstone such as the Devonian Woodford and Mississippian Barnett/Meramec. These formations are important sources and, more recently, reservoirs within the present-day Greater Permian Basin.

The Spraberry/Bone Spring was deposited as siliciclastic and carbonate turbidites and debris flows along with pelagic mudstones in a deep-water, basinal environment, while the Wolfcamp reservoirs consist of debris-flow, grain-flow and fine-grained pelagic sediments, which were also deposited in a basinal setting. The best carbonate reservoirs within the Wolfcamp and Spraberry/Bone Spring are generally found in close proximity to the Central Basin Platform, while mudstone reservoirs thicken basin-ward, away from the Central Basin Platform. The mudstone within these reservoirs is organically rich, which when buried to sufficient depth for thermal maturation, became the source of the hydrocarbons found both within the mudstones themselves and in the interbedded conventional clastic and carbonate reservoirs. Due to this complexity, the Wolfcamp and Spraberry/Bone Spring intervals are a hybrid reservoir system that contains characteristics of both unconventional and conventional reservoirs.

We have successfully developed several hybrid reservoir intervals within the Clearfork, Spraberry/Bone Spring, Wolfcamp and Barnett/Meramec formations since we began horizontal drilling in 2012. The mudstones and some clastics 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 3,413 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, 2019, net production from our Permian Basin acreage was 103,285 MBOE, or an average of 282,972 BOE/d, of which approximately 66% was oil, 18% was natural gas liquids and 16% 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.

Our publicly traded subsidiary Rattler owns the Fasken Center which has over 421,000 net rentable square feet within its two office towers and associated assets in Midland, Texas. We, Viper and Rattler are headquartered at the Fasken Center. We and unrelated third parties lease office space within the Fasken Center from Rattler under long-term lease agreements.

We and our subsidiaries also own field offices and related facilities in Midland and Reeves Counties, Texas. We believe that these facilities are adequate for our current operations.

Recent and Future Activity

During 2020, we expect to complete an estimated 320 to 360 gross (288 to 324 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2020 for drilling and infrastructure will be between $2.8 billion and $3.0 billion, consisting of $2.45 billion to $2.6 billion for horizontal drilling and completions including non-operated activity, $200 million to $225 million for midstream investments, excluding joint venture investments, and $150 million to $175 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions. During the year ended December 31, 2019, we drilled 330 gross (296 net) and completed 317 gross (289 net) operated horizontal wells. During the year ended December 31, 2019, our capital expenditures for drilling, completing and equipping wells were $2.6 billion. In addition, we spent $364 million for oil and gas midstream and infrastructure and $776 million for leasehold and mineral rights acquisitions.

We are operating 23 drilling rigs now including two rigs drilling produced water disposal wells and currently intend to operate between 20 and 23 rigs on average in 2020. 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.

With our current development plan, we expect to continue our strong PUD conversion ratio in 2020 by converting an estimated 35% of our PUDs to a proved developed category, and develop approximately 66% of the consolidated 2019 year-end PUD reserves by the end of 2021.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2019, 2018 and 2017 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, 2019 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 85% 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 15% 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 20 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, 2019, 2018 and 2017 (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.

	As of December 31,		
	2019	2018	2017
Estimated proved developed reserves:			
Oil (MBbls)	457,083	403,051	141,246
Natural gas (MMcf)	824,760	705,084	190,740
Natural gas liquids (MBbls)	165,173	125,509	35,412
Total (MBOE)	759,716	646,074	208,447
Estimated proved undeveloped reserves:			
Oil (MBbls)	253,820	223,885	91,935
Natural gas (MMcf)	294,051	343,565	94,629
Natural gas liquids (MBbls)	65,030	64,782	19,198
Total (MBOE)	367,859	345,928	126,905
Estimated Net Proved Reserves:			
Oil (MBbls)	710,903	626,936	233,181
Natural gas (MMcf)	1,118,811	1,048,649	285,369
Natural gas liquids (MBbls)	230,203	190,291	54,609
Total (MBOE)(1)	1,127,575	992,001	335,352
Percent proved developed	67%	65%	62%

(1) Estimates of reserves as of December 31, 2019, 2018 and 2017 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, 2019, 2018 and 2017, 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, 2019, our proved undeveloped reserves totaled 253,820 MBbls of oil, 294,051 MMcf of natural gas and 65,030 MBbls of natural gas liquids, for a total of 367,859 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Table of Contents

The following table includes the changes in PUD reserves for 2019:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2018	345,928
Undeveloped reserves transferred to developed	(120,920)
Revisions	(77,519)
Net purchases	4,542
Divestitures	(5,672)
Extensions and discoveries	221,500
Ending proved undeveloped reserves at December 31, 2019	367,859

The increase in proved undeveloped reserves was primarily attributable to extensions of 213,909 MBOE from 291 gross (262 net) wells in which we have a working interest and 7,591 MBOE from 97 gross wells in which Viper owns royalty interests. Of the 291 gross working interest wells, 64 were in the Delaware Basin. Transfers of 120,920 MBOE were the result of drilling or participating in 135 gross (119 net) horizontal wells in which we have a working interest and 79 gross wells in which we have a royalty interest or mineral interest through Viper. We own a working interest in 75 of the 79 gross Viper wells. Downward revisions of 77,519 MBOE resulted from 67,114 MBOE of PUD downgrades due to refinement of the PUD inventory following the Energen merger. These downgrades were offset with extensions. The remaining 10,405 MOE of downward revisions were mostly from lower benchmark commodity prices.

Costs incurred relating to the development of PUDs were approximately $956 million during 2019. Estimated future development costs relating to the development of PUDs are projected to be approximately $1.2 billion in 2020, $721 million in 2021, $641 million in 2022 and $576 million in 2023. 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, 2019, 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, 2019, none 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 tables set forth information regarding our net production of oil, natural gas and natural gas liquids by basin for each of the periods indicated:

	Year Ended December 31, 2019				Year Ended December 31, 2018			
	Midland Basin	Delaware Basin	Other(1)	Total	Midland Basin	Delaware Basin	Other(2)	Total
	(in thousands)							
Production Data:								
Oil (MBbls)	41,156	25,951	1,411	68,518	24,698	9,288	381	34,367
Natural gas (MMcf)	48,109	48,447	1,057	97,613	21,674	12,416	579	34,669
Natural gas liquids (MBbls)	10,485	7,826	187	18,498	5,493	1,866	106	7,465
Total (MBoe)	59,659	41,852	1,774	103,285	33,803	13,223	584	47,610

(1) Includes the Central Basin Platform, the Eagle Ford Shale and the Rockies.
(2) Includes the Eagle Ford Shale.

	December 31, 2017			
	Midland Basin	Delaware Basin	Other[1]	Total
	(in thousands)			
Production Data:				
Oil (MBbls)	17,553	3,865	—	21,418
Natural gas (MMcf)	15,893	4,761	6	20,660
Natural gas liquids (MBbls)	3,673	383	—	4,056
Total (MBoe)	23,875	5,042	1	28,917

(1) Includes the Eagle Ford Shale.

The following table sets forth certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2019	2018	2017
Average Prices:			
Oil ($ per Bbl)	$ 51.87	$ 54.66	$ 48.75
Natural gas ($ per Mcf)	0.68	1.76	2.53
Natural gas liquids ($ per Bbl)	14.42	25.47	22.20
Combined ($ per BOE)	37.63	44.73	41.02
Oil, hedged ($ per Bbl)[1]	51.96	51.20	48.94
Natural gas, hedged ($ per MMbtu)[1]	0.86	1.72	2.65
Natural gas liquids, hedged ($ per Bbl)[1]	15.20	25.46	—
Average price, hedged ($ per BOE)[1]	38.00	42.20	41.26
Average Costs per BOE:			
Lease operating expense	$ 4.74	$ 4.31	$ 4.38
Production and ad valorem taxes	2.40	2.79	2.54
Gathering and transportation expense	0.86	0.55	0.44
General and administrative - cash component	0.54	0.79	0.80
Total operating expense - cash	$ 8.54	$ 8.44	$ 8.16
General and administrative - non-cash component	$ 0.46	$ 0.57	$ 0.88
Depreciation, depletion and amortization	14.01	13.09	11.30
Interest expense, net	1.66	1.83	1.40
Merger and integration expense	—	0.77	—
Total expenses	$ 16.13	$ 16.26	$ 13.58

(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.

Wells Drilled and Completed in 2019

The following table sets forth the total number of operated horizontal wells drilled and completed during the year ended December 31, 2019:

	Year Ended December 31, 2019			
	Drilled		Completed	
Area	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	171	154	178	163
Delaware Basin	159	142	139	126
Total	330	296	317	289

As of December 31, 2019, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	833	768	1,004	913	1,837	1,681
Delaware Basin	—	—	485	453	485	453
Other	3	3	—	—	3	3
Total	836	771	1,489	1,366	2,325	2,137

Productive Wells

As of December 31, 2019, we owned an average unweighted 83% working interest in 2,656 gross (2,202 net) productive wells and an average 3.1% royalty interest in 4,161 additional wells. Through our subsidiary Viper, we own an average unweighted 3.4% royalty or mineral interest in 5,807 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.

The following table sets forth information regarding productive wells by basin as of December 31, 2019:

	Gross Wells	Net Wells
Midland Basin	1,993	1,717
Delaware Basin	660	482
Other	3	3
Total productive wells	2,656	2,202

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated by basin. 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, 2019					
	Midland Basin		**Delaware Basin**		**Total**	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	75	68	31	28	106	96
Dry	—	—	—	—	—	—
Exploratory:						
Productive	96	86	128	114	224	200
Dry	—	—	—	—	—	—
Total:						
Productive	171	154	159	142	330	296
Dry	—	—	—	—	—	—

	Year Ended December 31, 2018					
	Midland Basin		**Delaware Basin**		**Total**	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	67	58	21	20	88	78
Dry	—	—	—	—	—	—
Exploratory:						
Productive	50	43	38	35	88	78
Dry	—	—	—	—	—	—
Total:						
Productive	117	101	59	55	176	156
Dry	—	—	—	—	—	—

	Year Ended December 31, 2017					
	Midland Basin		**Delaware Basin**		**Total**	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	26	22	1	1	27	23
Dry	—	—	—	—	—	—
Exploratory:						
Productive	93	67	19	17	112	84
Dry	—	—	—	—	—	—
Total:						
Productive	119	89	20	18	139	107
Dry	—	—	—	—	—	—

Acreage

The following table sets forth information as of December 31, 2019 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage(3)	
Basin	**Gross(4)**	**Net(5)**	**Gross(4)**	**Net(5)**	**Gross(4)**	**Net(5)**
Conventional Permian	1,278	1,154	1,507	1,401	2,785	2,555
Delaware	92,408	75,815	103,763	79,481	196,171	155,296
Exploration	160	160	38,124	28,865	38,284	29,025
Midland	135,792	123,159	82,346	72,302	218,138	195,461
Total	229,638	200,288	225,740	182,049	455,378	382,337

(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, 2019, 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.

	2020		2021		2022		2023		2024	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Delaware	27,197	20,284	9,709	3,756	4,659	571	1,240	384	—	—
Exploration	18,608	18,568	4,405	3,035	—	—	7,218	4,535	—	—
Midland	6,145	3,569	1,358	835	2,039	1,816	—	—	—	—
Total	51,950	42,421	15,472	7,626	6,698	2,387	8,458	4,919	—	—

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, 2019, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company, which we refer to as Shell (27%); Plains Marketing, which we refer to as Plains (23%); and Vitol Inc., which we refer to as Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of our revenue: Shell Trading (26%); Koch Supply & Trading LP, which we refer to as Koch (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 (31%); Koch (19%); and Enterprise Crude Oil LLC (11%). 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 a firm quantity of 25,000 barrels of crude oil per day 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 Plains

In July 2019, our wholly-owned subsidiary, Energen Resources Corporation, which we refer to as Energen Resources, entered into a long-term crude oil sales agreement with Plains pursuant to which, among other things, our existing agreements with Plains were terminated. Our new agreement with Plains requires that we make available 50,000 barrels of crude oil per day until the date occurring ten years following the date service commences for ExxonMobil Oil Corporation, which we refer to as Exxon, pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier (plus extensions for force majeure). If during the term of our agreement we fail to deliver the required quantities of oil for any month other than for specified force majeure events or acts or omissions of Plains, we have agreed to pay Plains a specified per barrel amount, subject to escalation, multiplied by the deficiency volume. If during the term of the agreement we fail to deliver the quantities of oil for any month that we have committed for such month other than for specified force majeure events or acts or omissions of Plains, we have agreed to pay Plains a deficiency payment. We have also dedicated certain crude oil production attributable to certain of our interests to Plains in connection with this agreement. Pricing for our production under the Plains agreement (i) prior to the date service commences for Exxon pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier, is at a Midland WTI or WTL, as applicable, base price less certain costs and (ii) following the date service commences for Exxon pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier, for volumes up to 100,000 barrels of crude oil per day, is at a MEH WTI or WTL base price, as applicable, less certain costs.

Agreement with Shell

In December 2018, we entered into an oil purchase agreement with Shell, which was amended and restated in December 2019, in which Shell agreed to transport crude oil it purchases from us through the EPIC pipeline, with which we have an agreement for the transportation of certain crude oil. Our agreement with Shell provides for different purchase obligations during the pre-commencement and service commencement periods for the EPIC pipeline, and provides for a three-year term beginning on the service commencement date for the EPIC pipeline. Shell has the option to extend its purchase obligations for up to three one-year terms, but not beyond March 31, 2026 except in the event of force majeure. Our delivery obligation (i) prior to the full service commencement of the EPIC pipeline will be, subject to certain conditions, including our right to repurchase certain volumes, either 30,000 or 40,000 barrels of crude oil per day and (ii) during the full service term will not exceed 50,000 barrels of crude oil per day. In addition, our wholly-owned subsidiary Energen Resources has signed an agreement with Shell in which all or a portion of the 50,000 barrels of crude oil per day referenced in the previous sentence may also be satisfied by Energen Resources. During different pre-commencement periods, Shell has agreed to pay us the price per barrel of oil based on the arithmetic average of the daily settlement price for the “Light Sweet Crude Oil” Prompt Month future contracts reported by the NYMEX over the applicable one-month period, subject to certain adjustments, plus a Corpus Christi differential determined based on Shell’s average sales price for its WTI barrels in Corpus Christi less certain other costs, expenses and fees. During the full service term, the price per barrel of oil payable by Shell to us is based on calendar dated Brent pricing plus a negotiated differential generally based on certain Argus WTI Houston CIF Rotterdam and Platts Midland DAP Rotterdam pricing, less certain adjustments.

Agreements with Vitol

On October 18, 2018, we entered into an agreement with Vitol to, among other things, sell an average of 23,750 barrels of crude oil per day plus other agreed upon volumes. We are continuing to sell crude oil to Vitol on a month-to-month basis and expect to continue to do so under our existing agreement with Vitol until our new agreement with Vitol becomes effective. Under our new agreement with Vitol, we agreed to sell, and Vitol agreed to purchase, (i) subject to certain conditions, including accelerated commissioning service on the Gray Oak pipeline and completion of certain infrastructure connections, 50,000 barrels of crude oil per day on average during each month occurring during the first seven years of full service on the Gray Oak pipeline, (ii) subject to certain conditions and the satisfaction of other conditions, including full service on the Gray Oak Pipeline and completion of certain infrastructure connections, an additional 50,000 barrels of crude oil per day on average during each month occurring during the first seven years following satisfaction of such conditions, (iii) subject to certain conditions, including notice that transportation services on the EPIC pipeline are ready to commence and completion of certain infrastructure connections, an additional 50,000 barrels of crude oil per day on average during each month occurring during the first seven years following satisfaction of such conditions and (iv) such other volumes of crude oil as agreed by the parties. We are entitled to receive payment for such crude oil under netback pricing, whereby the price for our crude oil is determined based on a formula which takes into consideration the final purchase price obtained by Vitol in marketing such crude oil in certain third party transactions less certain costs. In connection therewith, Vitol has agreed to, among other things, use commercially reasonable efforts to (i) maximize the final purchase price to us and mitigate any costs factored into the price determination and (ii) acquire third party crude oil to cover any shortfall below our volumes commitments. Vitol also agrees to (i) use the same care and apply the same policies as it would exercise and apply if it were trading the subject crude oil for Vitol’s own account and (ii) transport such crude oil on certain designated pipelines, including the Gray Oak pipeline pursuant to rights we have obtained through our Gray Oak transportation services agreement described below under “—Transportation”, under third party shipper rights or term assignments, as applicable, prior to Vitol’s downstream marketing activities.

Competition

The oil and natural gas industry is intensely competitive, and in our upstream segment, 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.

In our midstream operations segment, as Rattler seeks to expand its crude oil, natural gas and water-related midstream services, it faces a high level of competition, including major integrated crude oil and natural gas companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store or market oil and natural gas. As Rattler seeks to expand to provide midstream services to third party producers, it similarly faces a high level of competition. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas or NGLs. Within the acreage dedicated by Rattler to us, Rattler does not compete with other midstream companies to provide us with midstream services as a result of our relationship and long-term dedications to Rattler’s midstream assets. However, we may continue to use third party service providers for certain midstream services within such dedicated acreage until the expiration or termination of certain pre-existing dedications.

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 and Delaware Basins are transported to purchasers by pipeline.

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%	87%	91%
% of produced water connected to pipeline	96%	96%	96%

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include a total of approximately 397,000 gross acres across all Rattler's service lines across the Midland and Delaware Basins.

We are also party to a transportation services agreement with Gray Oak Pipeline, LLC, pursuant to which we agreed to the accelerated commissioning service, or the ACS, on the Gray Oak pipeline in the amount of 50,000 barrels of crude oil per day. Under the ACS program, shippers must make a deficiency payment for any barrels not shipped during the ACS term, which expires the day before the Gray Oak pipeline goes into full service, which is currently anticipated to occur in the second quarter of 2020. ACS commenced in November 2019 and is ongoing. Due to restrictive API gravity provisions and the lack of markets, we have been unable to ship any volumes over the Gray Oak pipeline since the inception of the ACS.

Once full service commences on the Gray Oak pipeline, subject to the terms and conditions of this transportation services agreement, we will be required to ship 50,000 barrels per day of crude oil on the Gray Oak pipeline or pay a deficiency payment for any shortfall in volumes as measured on a quarterly basis. Such deficiency payments can be used as a credit against future shipments in excess of our minimum contract volume each quarter, subject to certain restrictions.

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. In our exploration and production business, 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. In our midstream operations business, the volumes of condensate produced at Rattler's processing facilities fluctuate seasonally, with volumes generally increasing in the winter months and decreasing in the summer months as a result of the physical properties of natural gas and comingled liquids. Severe or prolonged summers may adversely affect our results of operations in the midstream operations segment.

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. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. 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. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 rules. The 2015 rule and the 2019 repeal are subject to several ongoing legal challenges. Also, on January 23, 2020, the EPA and the Corps released a final rule replacing the 2015 rule, and significantly reducing the waters subject to federal regulation under the Clean Water Act. The rule is anticipated to generate further legal challenges. Further, on April 23, 2019, the EPA published an interpretive statement and request for comment, clarifying that the Clean Water Act's permitting program for pollutant discharges does not apply to releases of pollutants to groundwater. 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 rules expand 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 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.

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. On November 4, 2019, the Trump Administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement, or what terms would be included in such an agreement. 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 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.

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. In addition, on August 28, 2019, the EPA proposed amendments to the 2012 and 2016 New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. Legal challenges are anticipated and thus substantial uncertainty exists regarding the scope of these New Source Performance standards for oil and natural gas operations. The 2012 and 2016 New Source Performance 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.

Endangered Species

The federal Endangered Species Act, or ESA, and analogous state laws restrict activities that may affect listed endangered or threatened species or their habitats. If endangered species are located in areas where we operate, our operations or any work performed related to them could be prohibited or delayed or expensive mitigation may be required. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in compliance with the ESA. On August 12, 2019, the U.S. Fish and Wildlife Service and the National Oceanic and Atmospheric Administration's National Marine Fisheries Service jointly published final rules that, among other things, tighten the critical habitat designation process and eliminate certain automatic protections for threatened species going forward. Nevertheless, the designation of previously unprotected species in areas where we operate as threatened or endangered could result in the imposition of restrictions on our operations and consequently have a material adverse effect on our business.

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 Rattler LLC considers to be natural gas gathering pipelines, Rattler believes that its 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 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 results of operations and cash flow. In addition, if any of the 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 Rattler LLC considers its 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, there can be no assurance 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, Rattler LLC’s natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. 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 Rattler’s or our operations, but additional capital expenditures and increased operating costs may result 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.

Safety and Maintenance Regulation. In our midstream operations, Rattler LLC is subject to regulation by the U.S. Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

Rattler LLC is also subject to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States crude oil and natural gas transportation pipelines and some gathering pipelines in high-consequence areas within ten years. DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

The Pipeline Safety and Job Creation Act, enacted in 2011, and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, also known as the PIPES Act, enacted in 2016, amended the HLPSA and NGPSA and increased safety regulation. The Pipeline Safety and Job Creation Act doubles the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1.0 million to $2.0 million for a related series of violations (now increased for inflation to $218,647 and $2,186,465, respectively), and provides that these maximum penalty caps do not apply to civil enforcement actions, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. The PIPES Act ensures that the PHMSA completes the Pipeline Safety and Job Creation Act requirements; reforms PHMSA to be a more dynamic, data-driven regulator; and closes gaps in federal standards.

PHMSA has undertaken rulemakings to address many areas of this legislation. For example, on October 1, 2019, PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside High Consequence Areas. The rules, once effective, also extend reporting requirements to certain previously unregulated gathering lines. The safety enhancement requirements and other provisions of the Pipeline Safety and Job Creation Act and the PIPES Act, as well as any implementation of PHMSA rules thereunder and/or related rule making proceedings, could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. In addition, any material penalties or fines issued to us under these or other statutes, rules, regulations or orders could have an adverse impact on our business, financial condition, results of operation and cash flow.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards, and many states have undertaken responsibility to enforce the federal standards. The Railroad Commission of Texas is the agency vested with intrastate natural gas pipeline regulatory and enforcement authority in Texas. The Commission’s regulations adopt by reference the minimum federal safety standards for the transportation of natural gas. In addition, on December 17, 2019, the Commission adopted rules requiring that operators of gathering lines take 'appropriate' actions to fix safety hazards. We do not anticipate any significant problems in complying with applicable federal and state laws and regulations in Texas. Our gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. Moreover, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Rattler LLC and the entities in which it owns an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. Also, the Department of Homeland Security and other agencies such as the EPA continue to develop regulations concerning the security of industrial facilities, including crude oil and natural gas facilities. We are subject to a number of requirements and must prepare Federal Response Plans to comply. We must also prepare Risk Management Plans under the regulations promulgated by the EPA to implement the requirements under the CAA to prevent the accidental release of extremely hazardous substances. We have an internal program of inspection designed to monitor and enforce compliance with safeguard and security requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to safety and security.

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, 2019, we had approximately 712 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.

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;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the coronavirus;
- 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 WTI Futures Contract 1 price for crude oil has ranged from a low of $26.21 per barrel, or Bbl, in February 2016 to a high of $76.41 per Bbl in October 2018. The Natural Gas Futures Contract 1 price spot market price of natural gas has ranged from a low of $1.64 per MMBtu in March 2016 to a high of $4.84 per MMBtu in November 2018. During 2019, WTI Futures Contract 1 prices ranged from $46.54 to $66.30 per Bbl and the Natural Gas Futures Contract 1 spot market price of natural gas ranged from $2.07 to $3.59 per MMBtu. On January 31, 2020, the WTI Futures Contract 1 posted price for crude oil was $51.56 per Bbl and the Natural Gas Futures Contract 1 spot market price of natural gas was $1.84 per MMBtu, representing decreases of 22% and 49%, respectively, from the high of $66.30 per Bbl of oil and $3.59 per MMBtu for natural gas during 2019. In response to recent volatility in commodity prices, many producers have reduced their capital expenditure budgets. If the prices of oil and natural gas 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, the occurrence or threat of terrorist attacks in the United States or other countries and global or national health concerns 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 2019, our total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $3.1 billion. Our 2020 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $2.8 billion to $3.0 billion, representing an increase of 1% over our 2019 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 2020 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 12,310 gross (8,141 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage. As of December 31, 2019, only 477 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 3,382 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, 2019, we are the operator of, have participated in, or have acquired a total of 1,770 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, 2019, we had leases representing 42,421 net acres expiring in 2020, 7,626 net acres expiring in 2021, 2,387 net acres expiring in 2022, 4,919 net acres expiring in 2023 and no net acres expiring in 2024. 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 2020, 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, double-up swap contracts and three-way collars with corresponding put, short put and call options and may in the future enter into forward sale contracts or additional fixed price swap, fixed price basis swap, double-up swap derivatives or three-way collars for a portion of our production. Although we have hedged a portion of our estimated 2020 and 2021 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, double-up swap contracts and three-way collars with corresponding put, short 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 our three-way collar contracts, the counterparty is required to make a payment to us 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. We are 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.

To the extent that the prices of oil and natural gas remain at current levels or decline further, we may not be able to economically hedge future production at the same level as our current hedges, and our results of operations and financial condition may be negatively impacted. For additional information regarding our outstanding derivative contracts as of December 31, 2019, see Note 15—Derivatives to our consolidated financial statements included elsewhere in this report.

Our derivative transactions expose us to counterparty credit risk.

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit 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 us, which creates credit risk. We do not require collateral from our counterparties. We have entered into derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk by us.

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 crude oil agreements with Trafigura, Plains, Shell and Vitol under which, subject to certain terms and conditions, we are obligated to deliver specified quantities of oil to such companies. Our maximum delivery obligation under these agreements varies for different periods and depends in some cases upon certain conditions, such as the in-service dates for the Gray Oak pipeline and the EPIC pipeline as described in this report. 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 our oil purchase agreements, which may result in deficiency payments to certain counterparties or a default under such agreements and may have an adverse effect on our company.

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 $186 million at December 31, 2019) and receivables from purchasers of our oil and natural gas production (approximately $429 million at December 31, 2019). 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, 2019, three purchasers each accounted for more than 10% of our revenue: Shell (27%); Plains (23%); and Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of our revenue: Shell (26%); Koch (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 (31%); Koch (19%); and Enterprise Crude Oil LLC (11%). 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 $13.54, $12.62 and $11.11 for the years ended December 31, 2019, 2018 and 2017, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the years ended December 31, 2019, 2018 and 2017 was $1.4 billion, $595 million and $321 million, respectively.

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

An impairment on proved oil and natural gas properties of $790 million was recorded for the year ended December 31, 2019. No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2018 and 2017. 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, 2019, 2018 and 2017 (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, 2019, 2018 and 2017 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, 2019, 2018 and 2017, 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 33% of our total estimated proved reserves as of December 31, 2019, 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, 2019, 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, 2019, three purchasers each accounted for more than 10% of our revenue: Shell (27%); Plains (23%); and Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of our revenue: Shell (26%); Koch (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 (31%); Koch (19%); and Enterprise Crude Oil LLC (11%). 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 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.

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. For a more detailed discussion of federal laws concerning hydraulic fracturing, see "Items 1 and 2. Business and Properties—Regulation—Regulation of Hydraulic Fracturing."

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, ecologically or seismically sensitive 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 threatened or 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.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, which we refer to as Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, which we refer to as the CFTC, the SEC, and federal regulators of financial institutions, which we refer to as the Prudential Regulators, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the

Mandatory Clearing Rule, requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the End User Exception, establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the Margin Rule, setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the Non-Financial End User Exception, and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC has three times proposed a new version of this rule, with respect to which the comment period closed but the rule was not adopted, and another version of this rule, which we refer to as the Latest-Proposed Position Limit Rule, with respect to which the comment period will close on April 29, 2020 unless extended and a final rule may or may not be issued. The Latest-Proposed Position Limit Rule provides an exemption from the position limits for swaps that constitute "bona fide hedging positions" within the definition of such term under the Latest-Proposed Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Latest-Proposed Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and our existing and anticipated hedging positions constitute "bona fide hedging positions" under the Re-Proposed Position Limit Rule and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Latest-Proposed Position Limit Rule if and when it becomes effective, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as Foreign Regulations, which may apply to our transactions with counterparties subject to such Foreign Regulations, which we refer to as Foreign Counterparties, and the U.S. adopted law and rules, which we call the U.S. Resolution Stay Rules, clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Latest-Proposed Position Limit Rule is effected, such proposed rule and the U.S. Resolution Stay Rules could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulation, the U.S. Resolution Stay Rules and Foreign 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 Dodd-Frank Act 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 contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

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 Act, 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. On November 4, 2019, the Trump Administration submitted its formal notification of withdrawal to the United Nations. It is not clear what steps, if any, will be taken to negotiate a new agreement, or what terms would be included in such an agreement. 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.

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 subsidiary Rattler LLC’s 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 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 Rattler LLC’s 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 Rattler LLC’s 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. Rattler LLC’s 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 or Rattler LLC's operations, but we could be required to incur additional capital expenditures and increased operating costs depending on future legislative and regulatory changes.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The U.S. Department of Transportation, or DOT, through the PHMSA and state agencies, enforces safety regulations with respect to the design, construction, operation, maintenance, inspection and management of certain of Rattler LLC's pipeline facilities. The PHMSA requires pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high-consequence areas, or HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. The regulations require operators to (i) perform ongoing assessments of pipeline integrity, (ii) identify and characterize applicable threats to pipeline segments that could impact a HCA, (iii) improve data collection, integration and analysis, (iv) repair and remediate pipelines as necessary and (v) implement preventive and mitigating actions. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. The PHMSA's regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans, including extensive spill response training for pipeline personnel.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, also known as the Pipeline Safety and Job Creation Act, and the PIPES Act, are the most recent enactments of federal legislation to amend the NGPSA and the HLPSA which are pipeline safety laws requiring increased safety measures for natural gas and hazardous liquids pipelines. Among other things, the Pipeline Safety and Job Creation Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing and verification of the maximum allowable pressure of certain pipelines. The Pipeline Safety and Job Creation Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and from $1.0 million to $2.0 million for a related series of violations. Effective July 31, 2019, to account for inflation, those maximum civil penalties were increased to $218,647 per violation per day, with a maximum of $2,186,465 for a related series of violations. The PIPES Act ensures that the PHMSA completes the Pipeline Safety and Job Creation Act requirements; reforms PHMSA to be a more dynamic, data-driven regulator; and closes gaps in federal standards.

On October 1, 2019, PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside High Consequence Areas. The rules, once effective, also extend reporting requirements to certain previously unregulated gathering lines. The safety enhancement requirements and other provisions of the Pipeline Safety and Job Creation Act and the PIPES Act, as well as any implementation of PHMSA rules thereunder and/or related rule making proceedings, could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in increased operating costs that could have a material adverse effect on our or Rattler LLC's results of operations or financial position.

If third party pipelines or other facilities interconnected to Rattler LLC's midstream systems become partially or fully unavailable, or if the volumes we gather or treat do not meet the quality requirements of such pipelines or facilities, our midstream operations could be adversely affected.

Our subsidiary Rattler LLC's midstream systems are connected to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third party pipelines or facilities is not within our control. If any of these pipelines or facilities becomes unable to transport, treat or process natural gas or crude oil, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or facilities, our midstream operations could be adversely affected.

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

Our subsidiary Rattler 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 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 activities. 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 cash flows.

We recorded stock-based compensation expense in 2019, 2018 and 2017, 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, 2019, 2018 and 2017 we incurred $65 million, $37 million and $34 million, respectively, of stock based compensation expense, of which we capitalized $17 million, $10 million and $9 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 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

References in this section to "us, "we" or "our" shall mean Diamondback Energy, Inc. and Diamondback O&G LLC, collectively, unless otherwise specified.

We have relied in the past, and we may rely from time to time in the future, on borrowings under our revolving credit facility to fund a portion of our capital expenditures. Unless we are able to repay borrowings under the revolving credit facility with

cash flow from operations and proceeds from equity or debt offerings, implementing our capital programs may require an increase in our total leverage through additional debt issuances. In addition, a reduction in availability under our revolving credit facility and the inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.

We have historically relied on availability under our revolving credit facility to fund a portion of our capital expenditures. We expect that we will continue to fund a portion of our capital expenditures with borrowings under the revolving credit facility, cash flow from operations and the proceeds from debt and equity offerings. In the past, we have created availability under the revolving credit facility by repaying outstanding borrowings with the proceeds from debt or equity offerings. We cannot assure you that we will choose to or be able to access the capital markets to repay any such future borrowings. Instead, we may be required or choose to finance our capital expenditures through additional debt issuances, which would increase our total amount of debt outstanding. If the availability under the revolving credit facility were reduced, and we were otherwise unable to secure other sources of financing, we may be required to curtail our capital expenditures, which could limit our ability to fund our drilling activities and acquisitions or otherwise finance the capital expenditures necessary to replace our reserves.

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

As of December 31, 2019, we had total long-term debt of $5.4 billion, including $4.3 billion outstanding under our 5.375% Senior Notes due 2025, which we refer to as the 2025 Notes, the Energen Notes, our 2.875% Senior Notes due 2024, our 3.250% Senior Notes due 2026 and our 3.500% Senior Notes due 2029, which are collectively referred to, together with the 2025 Notes, as the senior notes, and $13 million outstanding under our revolving credit facility, and we had $1.99 billion available for borrowing under our revolving credit facility. As of December 31, 2019, Energen, one of our subsidiaries, had $539 million, which are collectively referred to as the Energen Notes. As of December 31, 2019, Viper LLC, one of our subsidiaries, had $97 million in outstanding borrowings, and $678 million available for borrowing, under its revolving credit facility and $500 million outstanding under its 5.375% Senior Notes due 2027. As of December 31, 2019, Rattler LLC, one of our subsidiaries, had $424 million in outstanding borrowings, and $176 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 our debt instruments, including any repurchase obligations that may arise thereunder;
- a significant portion of our cash flows could be used to service our indebtedness, which could reduce the funds available to us for operations and other purposes;
- our high level of debt could increase our vulnerability to general adverse economic and industry conditions;
  the covenants contained in the agreements governing certain of our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our 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;
- our high level of debt could limit our ability to access the capital markets to raise capital on favorable terms;
  our 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.

Our 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 certain of our existing and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.

Certain of our debt instruments 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 liens;
- sell or transfer assets;
- issue preferred stock;
- merge or consolidate with another entity;
- pay dividends or make other distributions;
- create unrestricted subsidiaries; and
- engage in transactions with affiliates.

Under our revolving credit facility we are allowed, 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 our revolving credit facility, we designated Viper, Viper’s general partner, Viper’s subsidiary, Rattler, Rattler’s general partner and Rattler’s subsidiaries as unrestricted subsidiaries, and upon such designation, they were automatically released from any and all obligations under the revolving credit facility, including the related guaranty. Further Viper, Viper’s general partner, Viper’s subsidiaries, Rattler, Rattler’s general partner and Rattler’s subsidiaries are designated as unrestricted subsidiaries under the indentures governing our outstanding senior notes.

We and our subsidiaries may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants and financial covenants contained in our and our subsidiaries’ debt instruments. As an example, our revolving credit facility requires us to maintain a total net debt to capitalization ratio. The requirement that we and our subsidiaries comply with these provisions may materially adversely affect our and our subsidiaries 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 the applicable debt instrument. If default occurs under our revolving credit facility, the lenders thereunder 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 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.

Our indebtedness is structurally subordinated to the indebtedness and other liabilities of our subsidiaries, and our obligations are not obligations of any of our subsidiaries.

Our senior indebtedness obligations are obligations exclusively of Diamondback Energy, Inc. and Diamondback O&G LLC, and not of any of our other subsidiaries. None of our subsidiaries is a guarantor of our senior indebtedness. Any assets of our subsidiaries will not be directly available to satisfy the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes. Except to the extent we are a creditor with recognized claims against our subsidiaries, all claims of creditors of our subsidiaries will have priority over our equity interests in such subsidiaries (and therefore the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes) with respect to the assets of such subsidiaries. Even if we are recognized as a creditor of one or more of our subsidiaries, our claims would still be effectively subordinated to any security interests in the assets of any such subsidiary and to any indebtedness or other liabilities of any such subsidiary senior to our claims. Consequently, our senior indebtedness will be structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries and any subsidiaries that we may in the future acquire or establish, As of December 31, 2019, Energen, one of our subsidiaries, had an aggregate of $539 million of notes, which are collectively referred to as the Energen Notes. As of December 31, 2019, Viper LLC, one of our subsidiaries, had $97 million in outstanding borrowings, and $678 million available for borrowing, under its revolving credit facility and $500 million outstanding under its 5.375% Senior Notes due 2027. As of December 31, 2019, Rattler LLC, one of our subsidiaries, had $424 million in outstanding borrowings, and $176 million available for borrowing, under its revolving credit facility.

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. The indenture governing the 2025 Notes restricts 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 depend on our subsidiaries for dividends, distributions and other payments.

We depend on our subsidiaries for dividends, distributions and other payments. We are a legal entity separate and distinct from our operating subsidiaries. There are statutory and regulatory limitations on the payment of dividends or distributions by certain of our subsidiaries to us. If our subsidiaries are unable to make dividend or distribution payments to us and sufficient cash or liquidity is not otherwise available, we may not be able to make dividend payments to our stockholders or principal and interest payments on our outstanding indebtedness.

We and our subsidiaries 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 and our subsidiaries' revolving credit facilities and the indentures restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2019, we had $13 million outstanding under our revolving credit facility, and we had $1.99 billion available for borrowing under our revolving credit facility As of December 31, 2019, Viper LLC had $97 million in outstanding borrowings, and $678 million available for borrowing, under its revolving credit facility. As of December 31, 2019, Rattler LLC had $424 million in outstanding borrowings, and $176 million available for borrowing, under its revolving credit facility. Further, the indentures governing our and our subsidiaries' notes allow us to issue additional notes incur certain other additional debt and 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, Viper LLC's and Rattler LLC's revolving credit facilities expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our and our subsidiaries' revolving credit facilities. The terms of our and our subsidiaries' revolving credit facilities provide for interest on borrowings at a floating rate equal to an alternate 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 0.125% to 1.0% in the case of the alternative base rate and from 1.125% to 2.0% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Both Viper LLC's and Rattler LLC's revolving credit facilities provide for interest on borrowings at floating rates, which are also tied to LIBOR. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. We have not hedged our interest rate exposure with respect to our floating rate debt. Accordingly, our interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. As of December 31, 2019, we had $13 million borrowings outstanding under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 3.20% on December 31, 2019. Viper LLC's weighted average interest rate on borrowings from its revolving credit facility was 4.30% during the year ended December 31, 2019. Rattler LLC's weighted average interest rate on borrowings from its revolving credit facility was 2.98% during the year ended December 31, 2019. As of December 31, 2019, Viper LLC had $97 million in outstanding borrowings, and $678 million available for borrowing, under its revolving credit facility. As of December 31, 2019, Rattler LLC had $424 million in outstanding borrowings, and $176 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.

On July 27, 2017, the U.K. Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established or if LIBOR will continue to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United States or elsewhere.

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 and repurchases of our common stock are each 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 on or repurchases of our common stock 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.

In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. This repurchase program is at the discretion of our board of directors and may be suspended from time to time, modified, extended or discontinued by our board of directors at any time.

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, 2019, we had a net operating loss, or NOL, carry forward of approximately $1.7 billion for federal income tax purposes, including $748 million acquired as part of the Energen acquisition. Although the NOL, and tax credits of $3 million, attributable to Energen's pre-acquisition activity are subject to an annual limitation under Section 382 of the Code, we do not expect that limitation to materially impact our utilization of those amounts

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

We are a party to various legal proceedings, disputes and claims arising in the course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

For additional information regarding contingencies, see Note 18—Commitments and Contingencies included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

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

Listing and Holders of Record

Our common stock is listed on the Nasdaq Select Global Market under the symbol "FANG". There were 20 holders of record of our common stock on February 13, 2020.

Dividend Policy

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. Beginning with the first quarter of 2019, the annual cash dividend was increased to $0.75 per share of our common stock. Additionally, beginning with the fourth quarter of 2019, the annual cash dividend was increased to $1.50 per share of our common stock. 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.

Repurchases of Equity Securities

Our common stock repurchase activity for the year ended December 31, 2019 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid Per Share(1)	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan(2)
	($ in millions, except per share amounts, shares in thousands)			
January 2019	0	$ —	0	$ 2,000
February 2019(3)	108	$ 102.14	0	$ 2,000
March 2019(3)	17	$ 102.93	0	$ 2,000
April 2019	0	$ —	0	$ 2,000
May 2019	40	$ 100.86	40	$ 1,996
June 2019	976	$ 102.04	976	$ 1,896
July 2019	995	$ 105.56	995	$ 1,791
August 2019	1,252	$ 97.53	1,252	$ 1,669
September 2019	707	$ 97.29	707	$ 1,600
October 2019	812	$ 84.97	812	$ 1,531
November 2019	994	$ 78.16	994	$ 1,454
December 2019(4)	609	$ 85.08	609	$ 1,402
Total	6,510	$ 93.83	6,385	

(1) The average price paid per share is net of any commissions paid to repurchase stock.
(2) In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. This repurchase program may be suspended from time to time, modified, extended or discontinued by our board of directors at any time.
(3) Acquired in connection with tax withholdings and payment of exercise price on equity compensation plans.
(4) Includes 108,942 shares that had not settled as of December 31, 2019.

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, 2019, 2018 and 2017 and the balance sheet data as of December 31, 2019 and 2018 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, 2016 and 2015 and the balance sheet data as of December 31, 2017, 2016 and 2015 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	Year Ended December 31,				
(In millions, except per share amounts, shares in thousands)	**2019**	**2018(1)**	**2017**	**2016**	**2015**
Statements of Operations Data:					
Total revenues	$ 3,964	$ 2,176	$ 1,205	$ 527	$ 447
Total costs and expenses	3,269	1,165	600	596	1,187
Income (loss) from operations	695	1,011	605	(69)	(740)
Other income (expense)	(333)	102	(108)	(96)	(9)
Income (loss) before income taxes	362	1,113	497	(165)	(749)
Provision for (benefit from) income taxes	47	168	(20)	—	(201)
Net income (loss)	315	945	517	(165)	(548)
Less: Net income attributable to non-controlling interest	75	99	35	—	3
Net income (loss) attributable to Diamondback Energy, Inc.	$ 240	$ 846	$ 482	$ (165)	$ (551)
Earnings per common share:					
Basic	$ 1.47	$ 8.09	$ 4.95	$ (2.20)	$ (8.74)
Diluted	$ 1.47	$ 8.06	$ 4.94	$ (2.20)	$ (8.74)
Weighted average common shares outstanding:					
Basic	163,493	104,622	97,458	75,077	63,019
Diluted	163,843	104,929	97,688	75,077	63,019
Cash dividends declared per common share	$ 0.9375	$ 0.5000	$ —	$ —	$ —

(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 Energen merger, through December 31, 2018.

	As of December 31,				
(In millions)	**2019**	**2018**	**2017**	**2016**	**2015**
Balance Sheet Data:					
Cash and cash equivalents	$ 123	$ 215	$ 112	$ 1,666	$ 20
Net property and equipment	21,835	20,372	7,344	3,391	2,598
Total assets	23,531	21,596	7,771	5,350	2,751
Current liabilities	1,263	1,019	577	209	141
Long-term debt	5,371	4,464	1,477	1,106	488
Total stockholders'/ members' equity(1)	13,249	13,700	5,255	3,697	1,876
Total equity	$ 14,906	$ 14,167	$ 5,582	$ 4,018	$ 2,109

(In millions)	Year Ended December 31, 2019	2018	2017	2016	2015
Other Financial Data:					
Net cash provided by operating activities	$ 2,734	$ 1,565	$ 889	$ 332	$ 417
Net cash used in investing activities	$ (3,888)	$ (3,503)	$ (3,132)	$ (1,310)	$ (895)
Net cash provided by financing activities	$ 1,062	$ 2,041	$ 689	$ 2,625	$ 468

(In millions)	Year Ended December 31, 2019	2018	2017	2016	2015
Consolidated Adjusted EBITDA(2)	$ 2,949	$ 1,538	$ 928	$ 388	$ 449

(1) For the years ended December 31, 2019, 2018, 2017, 2016 and 2015, total stockholders' equity excludes $738 million, $467 million, $327 million, $321 million and $233 million, respectively, of non-controlling interest related to Viper Energy Partners LP. For the year ended December 31, 2019, total stockholders' equity excludes $919 million of non-controlling interest related to Rattler Midstream 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

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

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

	Year Ended December 31,				
(In millions)	**2019**	**2018**	**2017**	**2016**	**2015**
Net income (loss)	$ 315	$ 945	$ 517	$ (165)	$ (548)
Non-cash loss (gain) on derivative instruments, net	188	(222)	84	27	113
Interest expense, net	172	87	41	41	41
Depreciation, depletion and amortization	1,447	623	327	178	218
Impairment of oil and natural gas properties	790	—	—	246	815
Non-cash equity-based compensation expense	65	37	34	33	24
Capitalized equity-based compensation expense	(17)	(10)	(9)	(7)	(6)
Asset retirement obligation accretion expense	7	2	1	1	1
Loss on extinguishment of debt	56	—	—	33	—
Gain (loss) on revaluation of investment	(5)	1	—	—	—
Merger and integration expense	—	36	—	—	—
Income tax (benefit) provision	47	168	(20)	—	(201)
Consolidated Adjusted EBITDA	3,065	1,667	975	387	457
Non-controlling interest in net (income) loss	(116)	(129)	(47)	1	(8)
Adjusted EBITDA attributable to Diamondback Energy, Inc.	$ 2,949	$ 1,538	$ 928	$ 388	$ 449

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 operate in two business segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas and (ii) through our subsidiary, Rattler, the midstream operations segment, which is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin.

Upstream Operations

In our upstream segment, 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.

As of December 31, 2019, we had approximately 382,337 net acres, which primarily consisted of approximately 195,461 net acres in the Midland Basin and approximately 155,296 net acres in the Delaware Basin. As of December 31, 2019, we had an estimated 12,310 gross horizontal locations that we believe to be economic at $60.00 per Bbl West Texas Intermediate, or WTI.

In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 814,224 gross acres and 24,304 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 50% of these net royalty acres are operated by us. We own Viper's general partner and, together with one of our subsidiaries, approximately 58% of the limited partner interest in Viper, represented by common units and Class B units. We, as the holder of the Class B units in Viper and Viper's general partner, as the holder of the general partner interest, are entitled to receive cash preferred distributions equal to 8% per annum on the outstanding amount of their respective capital contributions payable quarterly.

Midstream Operations

In our midstream operations segment, Rattler's crude oil infrastructure assets consist of gathering pipelines and metering facilities, which collectively gather crude oil for its customers. Rattler's facilities gather crude oil from horizontal and vertical wells in our ReWard, Spanish Trail, Pecos and Fivestones areas within the Permian Basin. Rattler's natural gas gathering and compression system consists of gathering pipelines, compression and metering facilities, which collectively service the production from our Pecos area assets within the Permian Basin. Rattler's water sourcing and distribution assets consists of water wells, frac pits, pipelines and water treatment facilities, which collectively gather and distribute water from Permian Basin aquifers to the drilling and completion sites through buried pipelines and temporary surface pipelines. Rattler's gathering and disposal system spans approximately 474 miles and consists of gathering pipelines along with produced water disposal, or PWD, wells and facilities which collectively gather and dispose of produced water from operations throughout our Permian Basin acreage.

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include substantial acreage dedications.

2019 Transactions and Recent Developments

Rattler Midstream LP

Rattler is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol “RTLR”. Rattler was formed by us in July 2018 to own, operate, develop and acquire midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Rattler Midstream GP LLC, or Rattler’s General Partner, a wholly-owned subsidiary of us, serves as the general partner of Rattler. As of December 31, 2019, we owned approximately 71% of Rattler’s total units outstanding.

In May 2019, Rattler completed its initial public offering, which we refer to as the Rattler Offering. Prior to the completion of the Rattler Offering, we owned all of the general and limited partner interests in Rattler. The Rattler Offering consisted of an aggregate of 43,700,000 common units representing approximately 29% of the limited partner interests in Rattler at a price to the public of $17.50 per common unit, which included 5,700,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms which closed on May 30, 2019. Rattler received net proceeds of approximately $720 million from the sale of these common units, after deducting offering expenses and underwriting discounts and commissions.

In connection with the completion of the Rattler Offering, Rattler (i) issued 107,815,152 Class B units representing an aggregate 71% voting limited partner interest in Rattler in exchange for a $1 million cash contribution from us, (ii) issued a general partner interest in Rattler to Rattler’s general partner, in exchange for a $1 million cash contribution from Rattler’s general partner, and (iii) caused Rattler LLC to make a distribution of approximately $727 million to us. We, as the beneficial holder of the Class B units, and Rattler’s general partner, as the holder of the general partner interest, are entitled to receive cash preferred distributions equal to 8% per annum on the outstanding amount of their respective $1 million capital contributions, payable quarterly.

Fourth Quarter 2019 Dividend Declaration and Increase

On February 14, 2020, our board of directors declared a cash dividend for the fourth quarter of 2019 of $0.3750 per share of common stock, payable on March 10, 2020 to our stockholders of record at the close of business on March 3, 2020, representing an increase of $0.1875 per share from the previously paid quarterly dividend.

Stock Repurchase Program

In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. This repurchase program is another component of our capital return program that includes the quarterly dividend discussed above. We anticipate that the repurchase program will be funded primarily by free cash flow generated from operations and liquidity events such as the sale of assets. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require us to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. During the year ended December 31, 2019, we repurchased approximately $598 million of common stock under our repurchase program. As of December 31, 2019, $1.4 billion remains available for use to repurchase shares under our common stock repurchase program.

Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

On May 23, 2019, we completed our divestiture of 6,589 net acres of certain non-core Permian assets, which we acquired in the Energen merger, for an aggregate sale price of $37 million. This divestiture did not result in a gain or loss because it did not have a significant effect on our reserve base or depreciation, depletion and amortization rate.

On July 1, 2019, we completed our divestiture of 103,750 net acres of certain conventional and non-core Permian assets, which we acquired in the Energen merger, for an aggregate sale price of $285 million. This divestiture did not result in a gain or loss because it did not have a significant effect on our reserve base or depreciation, depletion and amortization rate.

Viper’s Equity Offering

On March 1, 2019, Viper completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, we owned approximately 54% of Viper’s total units then outstanding. Viper received net proceeds from this offering of approximately $341 million, after deducting underwriting discounts and commissions and estimated offering expenses. Viper used the net proceeds to purchase units of Viper LLC. Viper LLC in turn used the net proceeds to repay a portion of the outstanding borrowings under its revolving credit facility and finance acquisitions during the period.

Drop-Down

On October 1, 2019, we completed a transaction to divest certain mineral and royalty interests to Viper for 18.3 million of Viper's newly-issued Class B units, 18.3 million newly-issued units of Viper LLC with a fair value of $497 million and $190 million in cash, after giving effect to closing adjustments for net title benefits, which we refer to as the Drop-Down. The mineral and royalty interests divested in the Drop-Down represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by us, and have an average net royalty interest of approximately 3.2%.

Increase in the Borrowing Base under Viper LLC's Revolving Credit Facility

In connection with Viper LLC's fall redetermination in November 2019, the borrowing base under Viper LLC's revolving credit facility was increased from $725 million to $775 million.

Viper's Notes Offering

On October 16, 2019, Viper completed an offering, which we refer to as the Viper Notes Offering, of $500 million in aggregate principal amount of its 5.375% senior notes due 2027, which we refer to as the Viper Notes. Viper received net proceeds of approximately $490 million from the Viper Notes Offering. Viper loaned the gross proceeds to Viper LLC. Viper LLC used the proceeds from the Viper Notes Offering to pay down borrowings under its revolving credit facility.

December 2019 Notes Offering

On December 5, 2019, we issued $1.0 billion in aggregate principal amount of 2.875% senior notes due 2024, which we refer to as the 2024 notes, $800 million in aggregate principal amount of 3.250% senior notes due 2026, which we refer to as the 2026 notes, and $1.2 billion aggregate principal amount of 3.500% senior notes due 2029, which we refer to as the 2029 notes and, together with the 2024 notes and the 2026 notes, the December 2019 Notes. The 2024 notes will mature on December 1, 2024, the 2026 notes will mature on December 1, 2026 and the 2029 notes will mature on December 1, 2029. Interest will accrue and be payable semi-annually, in arrears on June 1 and December 1 of each year, commencing on June 1, 2020. The December 2019 Notes are fully and unconditionally guaranteed by Diamondback O&G LLC.

Redemption of the Outstanding 4.750% Senior Notes.

On December 20, 2019, we redeemed all of our then outstanding 4.750% Senior Notes due 2024, which we refer to as the 4.750% senior notes, with a portion of our net proceeds from the issuance of the December 2019 Notes.

Operational Update

Our development program is focused entirely within the Permian Basin, where we continue to focus on long-lateral multi-well pad development. Our horizontal development consists of multiple targeted intervals, primarily within the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Springs formations in the Delaware Basin.

We are operating 23 drilling rigs now including two rigs drilling produced water disposal wells and currently intend to operate between 20 and 23 drilling rigs in 2020 on average across our asset base in the Midland and Delaware Basins.

In the Midland Basin, we continued to 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 a significant number of 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 2020, we expect to focus development on these areas.

We continue to focus on low cost operations and best in class execution. To combat potential fluctuation in 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 2020 drilling and completion budget accounts for capital costs that we believe cover potential increases in our service costs during the year.

In 2020, we remain focused on navigating our industry challenges by staying disciplined, improving our industry-leading cost structure, growing production, increasing environmental transparency and returning more cash to our stockholders as evidenced by our quarterly dividend increase beginning with the fourth quarter of 2019.

2020 Capital Budget

We have currently budgeted a 2020 total capital spend of $2.8 billion to $3.0 billion, consisting of $2.45 billion to $2.6 billion for horizontal drilling and completions including non-operated activity, $200 million to $225 million for midstream investments, excluding joint venture investments, and $150 million to $175 million for infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions. We expect to drill and complete 320 to 360 gross horizontal wells in 2020. Should commodity prices weaken further or remain weak for an extended period of time, we intend to act responsibly and, consistent with our prior practices, reduce capital spending. If commodity prices strengthen, we intend to grow oil production within our 2020 budget and return cash to our stockholders or pay down indebtedness.

Reserves and pricing

Ryder Scott prepared estimates of our proved reserves at December 31, 2019 and 2018 (which include estimated proved reserves attributable to Viper). The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

	As of December 31,	
	2019	**2018**
Estimated Net Proved Reserves:		
Oil (MBbls)	710,903	626,936
Natural gas (MMcf)	1,118,811	1,048,649
Natural gas liquids (MBbls)	230,203	190,291
Total (MBOE)	1,127,575	992,001

	Unweighted Arithmetic Average First-Day-of-the-Month Prices	
	2019	**2018**
Oil (per Bbl)	$ 51.88	$ 59.63
Natural gas (per Mcf)	$ 0.18	$ 1.47
Natural gas liquids (per Bbl)	$ 15.65	$ 24.43

Sources of our revenue

In our upstream segment, our main sources of revenues are the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing.

In our midstream operations segment, our results are primarily driven by: the volumes of crude oil that Rattler gathers, transports and delivers; natural gas that Rattler gathers, compresses, transports and delivers; water that Rattler sources, transports and delivers; and produced water that Rattler gathers, transports and disposes of, and the fees Rattler charges per unit of throughput for our midstream services.

The following table presents the sources of our oil and natural gas revenues for the years presented:

	Year Ended December 31,	
	2019	2018
Revenues:		
Oil sales	91%	88%
Natural gas sales	2%	3%
Natural gas liquid sales	7%	9%
	100%	100%

Commodity Prices

Since our production, in our exploration and production business, consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas or natural gas liquids prices. Viper, as the owner of mineral interests, is also indirectly exposed to fluctuations in commodity prices. Oil, natural gas and natural gas liquids prices have historically been volatile. Lower commodity prices may not only decrease our revenues, but also potentially the amount of oil and natural gas that we can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be redetermined at the discretion of our lenders.

In our midstream operations business, we have indirect exposure to commodity price risk in that persistent low commodity prices may cause us or Rattler’s other customers to delay drilling or shut in production, which would reduce the volumes available for gathering and processing by our infrastructure assets. If we or Rattler’s other customers delay drilling or temporarily shut in production due to persistently low commodity prices or for any other reason, our revenue in the midstream operations segment could decrease, as Rattler’s commercial agreements do not contain minimum volume commitments.

The following table sets forth information related to commodity prices for the following periods:

	Year Ended December 31,	
	2019	2018
High and Low Futures Contract Prices:		
Oil ($/Bbl, WTI Futures Contract 1)		
High	$ 66.30	$ 76.41
Low	$ 46.54	$ 42.53
Natural Gas ($/MMBtu, Futures Contract 1)		
High	$ 3.59	$ 4.84
Low	$ 2.07	$ 2.55
Average realized oil price ($/Bbl)	$ 51.87	$ 54.66
Average WTI Futures Contract 1 ($/Bbl)	$ 57.04	$ 64.90
Differential to WTI Futures Contract 1	$ (5.17)	$ (10.24)
Average realized oil price to WTI Futures Contract 1	91%	84%
Average realized natural gas price ($/Mcf)	$ 0.68	$ 1.76
Average Natural Gas Futures Contract 1 ($/Mcf)	$ 2.53	$ 3.07
Differential to Natural Gas Futures Contract 1	$ (1.85)	$ (1.31)
Average realized natural gas price to Natural Gas Futures Contract 1	27%	57%
Average realized natural gas liquids price ($/Bbl)	$ 14.42	$ 25.47
Average WTI Futures Contract 1 ($/Bbl)	$ 57.04	$ 64.90
Average realized natural gas liquids price to WTI Futures Contract 1	25%	39%

On December 31, 2019, the WTI Futures Contract 1 price for crude oil was $61.06 per Bbl and the Natural Gas Futures Contract 1 price was $2.19 per MMBtu.

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.

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.

Results of Operations

For a discussion of the results of operations for the year ended December 31, 2018 as compared to the year ended December 31, 2017 refer to Part II, Item 7. Management's Discussion and Analysis in our 2018 Form 10-K, which was filed with the SEC on February 25, 2019, which discussion is incorporated in this report by reference from such prior report on Form 10-K. The following table sets forth selected historical operating data for the periods indicated:

	Year Ended December 31,	
	2019	**2018**
Production Data:		
Oil (MBbls)	68,518	34,367
Natural gas (MMcf)	97,613	34,669
Natural gas liquids (MBbls)	18,498	7,465
Combined volumes (MBOE)	103,285	47,610
Daily oil volumes (BO/d)	187,721	94,156
Daily combined volumes (BOE/d)	282,972	130,439
Average Prices:		
Oil ($ per Bbl)	$ 51.87	$ 54.66
Natural gas ($ per Mcf)	$ 0.68	$ 1.76
Natural gas liquids ($ per Bbl)	$ 14.42	$ 25.47
Combined ($ per BOE)	$ 37.63	$ 44.73
Oil, hedged ($ per Bbl)(1)	$ 51.96	$ 51.20
Natural gas, hedged ($ per MMbtu)(1)	$ 0.86	$ 1.72
Natural gas liquids, hedged ($ per Bbl)(1)	$ 15.20	$ 25.46
Average price, hedged ($ per BOE)(1)	$ 38.00	$ 42.20

(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.

Production Data

Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. The following tables set forth our production data for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	**2018**
Oil (MBbls)	66%	72%
Natural gas (MMcf)	16%	12%
Natural gas liquids (MBbls)	18%	16%
	100%	100%

Comparison of the Years Ended December 31, 2019 and 2018

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $1.8 billion, or 82%, to $3.9 billion for the year ended December 31, 2019 from $2.1 billion for the year ended December 31, 2018. 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 152,533 BOE/d to 282,972 BOE/d during the year ended December 31, 2019 from 130,439 BOE/d during the year ended December 31, 2018. The total increase in revenue of approximately $1.8 billion is attributable to higher oil, natural gas liquids and natural gas production volumes, partially offset by lower average sales prices for the year ended December 31, 2019 as compared to the year ended December 31, 2018. The increase in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 34,151 MBbls of oil, 62,944 MMcf of natural gas and 11,033 MBbls of natural gas liquids for the year ended December 31, 2019 as compared to the year ended December 31, 2018.

The net dollar effect of the change in prices of approximately $501 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 change in production of approximately $2.3 billion (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 millions)
Effect of changes in price:			
Oil	$ (2.79)	68,518	$ (191)
Natural gas	$ (1.08)	97,613	$ (106)
Natural gas liquids	$ (11.05)	18,498	$ (204)
Total revenues due to change in price			$ (501)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change
			(in millions)
Effect of changes in production volumes:			
Oil	34,151	$ 54.66	$ 1,867
Natural gas	62,944	$ 1.76	$ 110
Natural gas liquids	11,033	$ 25.47	$ 281
Total change in revenues			$ 2,258
			$ 1,757

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

Lease Bonus Revenue. The following table shows lease bonus revenue for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Lease bonus revenue	$ 4	$ 3

Lease bonus revenue for the year ended December 31, 2019 was attributable to lease bonus payments of less than $1 million to extend the term of seven leases and lease bonus payments of $3 million on 12 new leases. Lease bonus revenue for the year ended December 31, 2018 was attributable to lease bonus payments of $1 million to extend the term of two leases and lease bonus payments of $2 million on five new leases.

Midstream Services Revenue. The following table shows midstream services revenue for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Midstream services revenue	$ 64	$ 34

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. The following table shows lease operating expenses for the years ended December 31, 2019 and 2018:

	Year Ended December 31,			
	2019		2018	
(in millions, except per BOE amounts)	Amount	Per BOE	Amount	Per BOE
Lease operating expenses	$ 490	$ 4.74	$ 205	$ 4.31

Lease operating expenses for the year ended December 31, 2019 as compared to the year ended December 31, 2018 increased by $285 million, or $0.43 per BOE. In both cases, lease operating expenses increased primarily due to increased power generation costs as a result of reduced electrical availability as well as increased production and the higher cost of the Central Basin Platform assets which were divested during 2019. We are actively working to mitigate this issue and expect these costs to decrease in the future.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the years ended December 31, 2019 and 2018:

	Year Ended December 31,			
	2019		2018	
(in millions, except per BOE amounts)	Amount	Per BOE	Amount	Per BOE
Production taxes	$ 184	$ 1.78	$ 104	$ 2.18
Ad valorem taxes	64	0.62	29	0.61
Total production and ad valorem expense	$ 248	$ 2.40	$ 133	$ 2.79

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. Production taxes for the year ended December 31, 2019 as compared to the year ended December 31, 2018 increased by $80 million due to increased overall production from acquisitions and well completions. Production taxes per BOE for the year ended December 31, 2019 as compared to the year ended December 31, 2018 decreased by $0.40 primarily due to a higher percentage increase in production volumes as compared to production taxes. Ad valorem taxes for the year ended December 31, 2019 as compared to the year ended December 31, 2018 increased by $35 million due to the addition of acquired and completed wells from the latter half of 2019.

Midstream Services Expense. The following table shows midstream services expense for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Midstream services expense	$ 91	$ 72

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. Midstream services expense for the year ended December 31, 2019 as compared to the year ended December 31, 2018, increased by $19 million primarily due to increased volume and build out of the Rattler systems.

Depreciation, Depletion and Amortization. The following table provides the components of our depreciation, depletion and amortization expense for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions, except BOE amounts)	
Depletion of proved oil and natural gas properties	$ 1,398	$ 595
Depreciation of midstream assets	33	19
Depreciation of other property and equipment	16	9
Depreciation, depletion and amortization expense	$ 1,447	$ 623
Oil and natural gas properties depreciation, depletion and amortization per BOE	$ 13.54	$ 12.62

The increase in depletion of proved oil and natural gas properties of $803 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018 resulted primarily from higher production levels and an increase in net book value on new reserves added.

Impairment of Oil and Natural Gas Properties. The following table shows impairment of oil and natural gas properties for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Impairment of oil and natural gas properties	$ 790	$ —

General and Administrative Expenses. The following table shows general and administrative expenses for the years ended December 31, 2019 and 2018:

	Year Ended December 31,			
	2019		2018	
(in millions, except per BOE amounts)	Amount	Per BOE	Amount	Per BOE
General and administrative expenses	$ 56	$ 0.54	$ 38	$ 0.79
Non-cash stock-based compensation	48	0.46	27	0.57
Total general and administrative expenses	$ 104	$ 1.00	$ 65	$ 1.36

General and administrative expenses for the year ended December 31, 2019 as compared to the year ended December 31, 2018 increased by $39 million primarily due to an increase in salaries and benefits as a result of increased head count.

Net Interest Expense. The following table shows net interest expense for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Net interest expense	$ 172	$ 87

Net interest expense for the year ended December 31, 2019 as compared to the year ended December 31, 2018, increased by $85 million. This increase was primarily due to increased average borrowings under our credit facility partially offset by a lower interest rate during the year ended December 31, 2019 as compared to the year ended December 31, 2018 as well as an increase in interest expense of $2 million related to our DrillCo Agreement.

Derivatives. The following table shows the gain (loss) on derivative instruments, net for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Change in fair value of open non-hedge derivative instruments	$ (188)	$ 222
Gain (loss) on settlement of non-hedge derivative instruments	80	(121)
Gain (loss) on derivative instruments	$ (108)	$ 101

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."

Provision for Income Taxes. The following table shows provision for income taxes for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Provision for income taxes	$ 47	$ 168

The change in our income tax provision was primarily due to the decrease in pre-tax income for the year ended December 31, 2019 and the change in the deferred income tax benefit resulting from estimated deferred taxes recognized as a result of Viper's change in tax status for the years ended December 31, 2019 and 2018.

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, 2019 and 2018 are presented below:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Net cash provided by operating activities	$ 2,734	$ 1,565
Net cash used in investing activities	(3,888)	(3,503)
Net cash provided by financing activities	1,062	2,041
Net change in cash	$ (92)	$ 103

Operating Activities

Net cash provided by operating activities was $2.7 billion for the year ended December 31, 2019 as compared to $1.6 billion for the year ended December 31, 2018. 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 production during the year ended December 31, 2019, partially offset by lower average sales prices.

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

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $3.9 billion and $3.5 billion during the years ended December 31, 2019 and 2018, respectively.

During the year ended December 31, 2019, we spent (a) $2.7 billion on capital expenditures in conjunction with our drilling program, in which we drilled 330 gross (296 net) horizontal wells and completed 317 gross (289 net) operated horizontal wells, (b) $244 million on additions to midstream assets, (c) $333 million for the acquisition of mineral interests, (d) $443 million on leasehold acquisitions, (e) $5 million for the purchase of other property and equipment, (f) $1 million on investment in real estate and (g) $485 million on equity method investments.

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 million on additions to midstream assets, (c) $440 million for the acquisition of mineral interests, (d) $1.4 billion on leasehold acquisitions, (e) $7 million for the purchase of other property and equipment and (f) $111 million on investment in real estate.

Our investing activities for the years ended December 31, 2019 and 2018 are summarized in the following table:

	Year Ended December 31,	
	2019	**2018**
	(in thousands)	
Drilling, completion and infrastructure	$ (2,677)	$ (1,461)
Additions to midstream assets	(244)	(204)
Acquisition of leasehold interests	(443)	(1,371)
Acquisition of mineral interests	(333)	(440)
Purchase of other property, equipment and land	(5)	(7)
Investment in real estate	(1)	(111)
Proceeds from sale of assets	300	80
Funds held in escrow	—	11
Equity investments	(485)	—
Net cash used in investing activities	$ (3,888)	$ (3,503)

Financing Activities

References in this section to “us, “we” or “our” shall mean Diamondback Energy, Inc. and Diamondback O&G LLC, collectively, unless otherwise specified.

Net cash provided by financing activities for the years ended December 31, 2019 and 2018 was $1.1 billion and $2.0 billion, respectively.

During the year ended December 31, 2019, the amount provided by financing activities was primarily attributable to $341 million in net proceeds from Viper’s public offering completed on March 1, 2019, $720 million in net proceeds from the Rattler Offering, $39 million in proceeds from joint ventures and $2.2 billion in proceeds from the December 2019 Notes, net of repayments, partially offset by $1.4 billion of repayments, net of borrowings under our credit facility, $44 million of premium on debt extinguishment, $122 million of distributions to non-controlling interest, $13 million of share repurchases for tax withholdings, $593 million of share repurchases as part of our stock repurchase program and $112 million of dividends to stockholders.

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 million of repayments under Energen’s credit facility and an aggregate of $305 million of net proceeds from Viper’s public offerings, partially offset by $98 million of distributions to non-controlling interest and $37 million of dividends to stockholders.

4.750% Senior Notes

On October 28, 2016, we issued $500.0 million in aggregate principal amount of 4.750% senior notes due 2024 under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On September 25, 2018, we issued $750 million aggregate principal amount of new 4.750% senior notes as additional notes under, and subject to the terms of the same indenture governing the 4.750% senior notes. We received approximately $741 million in net proceeds, after deducting the initial purchasers' discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the 4.750% senior notes. We used a portion of the net proceeds from the issuance of the 4.750% senior 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 acquisition of certain assets from Ajax Resources LLC.

On December 20, 2019, we redeemed all of the outstanding 4.750% senior notes, which we refer to as the Redemption Date. The redemption payment, which we refer to the Redemption Payment, included $1.25 billion of outstanding principal at a redemption price of 103.563% of the principal amount of the 4.750% senior notes, plus accrued and unpaid interest on the outstanding principal amount to the Redemption Date. On December 5, 2019, the indenture governing the 4.750% senior notes was fully satisfied and discharged and the guarantors were released from their guarantees of the 4.750% senior notes. The 4.750% senior notes, which bore interest at 4.750% per year, were scheduled to mature on November 1, 2024. On the Redemption Date, the Redemption Price will be paid to the holders of the 4.750% senior notes. We funded the Redemption Payment with a portion of our net proceeds from the issuance of the December 2019 Notes.

The 4.750% senior notes, bore 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 would have matured on November 1, 2024. All of our restricted subsidiaries that guaranteed our revolving credit facility guaranteed the 4.750% senior notes; provided, however, that the 4.750% senior notes were not guaranteed by Viper, Viper's General Partner, Viper LLC, Rattler, Rattler's General Partner or Rattler LLC.

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 as additional notes under the 2025 indenture, which we refer to as the new 2025 notes and, together with the existing 2025 notes, as the 2025 senior notes. We received approximately $308.4 million in net proceeds, after deducting the initial purchaser's discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2025 notes. We used the net proceeds from the issuance of the new 2025 notes to repay a portion of the outstanding borrowings under our revolving credit facility.

The 2025 senior notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year and will mature on May 31, 2025. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility guarantee the 2025 senior notes. Currently, the 2025 senior notes are not guaranteed by any of our subsidiaries other than Diamondback O&G LLC and will not be guaranteed by any of our future unrestricted subsidiaries.

For additional information regarding the 2025 senior notes, see Note 10—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

December 2019 Notes Offering

On December 5, 2019, we issued $1.0 billion in aggregate principal amount of 2.875% senior notes due 2024, $800 million in aggregate principal amount of 3.250% senior notes due 2026 and $1.2 billion aggregate principal amount of 3.500% senior notes due 2029. The 2024 notes will mature on December 1, 2024, the 2026 notes will mature on December 1, 2026 and the 2029 notes will mature on December 1, 2029. Interest will accrue and be payable semi-annually, in arrears on June 1 and December 1 of each year, commencing on June 1, 2020. The December 2019 notes are fully and unconditionally guaranteed by Diamondback O&G LLC and are not guaranteed by any of our other subsidiaries.

The December 2019 notes were issued under an indenture, dated as of December 5, 2019, among us and Wells Fargo Bank, as the trustee, as supplemented by the first supplemental indenture dated as of December 5, 2019, which we refer to as the December 2019 Notes Indenture. The December 2019 Notes Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of certain of our subsidiaries to incur liens securing funded indebtedness and on our ability to consolidate, merge or sell, convey, transfer or lease all or substantially all of our assets.

For additional information regarding the December 2019 Notes, see Note 10—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

Second Amended and Restated Credit Facility

We and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, as amended, 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. On June 28, 2019, the credit agreement was amended pursuant to an eleventh amendment, which implemented certain changes to the credit facility for the period on and after the date on which our unsecured debt achieves an investment grade rating from two rating agencies and certain other conditions in the credit agreement are satisfied (the "investment grade changeover date"). At December 31, 2019, the maximum credit amount available under the credit agreement is $2.0 billion. As of December 31, 2019, we had approximately $13 million of outstanding borrowings under our revolving credit facility and $1.99 billion available for future borrowings under our revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement, and as of December 31, 2019, the credit agreement is guaranteed by Diamondback Energy, Inc. None of our other subsidiaries are guarantors under our revolving credit facility. On December 5, 2019, Diamondback O&G LLC delivered a letter notifying the administrative agent under the credit agreement that as of such date, each of the guarantors, other than Diamondback Energy, Inc., ceased to be a guarantor under the credit agreement.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.125% to 1.0% per annum and from 1.125% to 2.0% per annum in the case of LIBOR, in each case, depending on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt. We are obligated to pay a quarterly commitment fee ranging from 0.125% to 0.350% per year on the unused portion of the commitment, based on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt.

Loan principal may be optionally prepaid from time to time without premium or penalty (other than customary LIBOR breakage). Loan principal is required to be repaid (a) to the extent the loan amount exceeds the commitment due to any termination or reduction of the aggregate maximum credit amount and (b) at the maturity date of November 1, 2022.

The credit agreement contains a financial covenant that requires us to maintain a total net debt to capitalization ratio (as defined in the credit agreement) of no more than 65%. Our non-guarantor restricted subsidiaries may incur debt for borrowed money in an aggregate principal amount up to 15% of consolidated net tangible assets (as defined in the credit agreement) and we and our restricted subsidiaries may incur liens if the aggregate amount of debt secured by such liens does not exceed 15% of consolidated net tangible assets.

As of December 31, 2019, we were in compliance with all financial covenants under our revolving credit facility, as then in effect. 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.

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 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. As of December 31, 2019, the Energen Notes consist of: (a) $399 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (2) $108 million of 7.125% notes due on February 15, 2028, (3) $21 million of 7.32% notes due on July 28, 2022, and (4) $11 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 if any, and are effectively subordinated to Energen's senior secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness. Neither we nor any of our subsidiaries guarantee the Energen Notes.

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

Viper's Facility-Wells Fargo Bank

On July 20, 2018, Viper LLC, as borrower, entered into an amended and restated credit agreement with Viper, as guarantor, Wells Fargo, as administrative agent, and the other lenders. The credit agreement, as amended, which we refer to as the Viper credit agreement, provides for a revolving credit facility in the maximum credit amount of $2 billion and a borrowing base based on Viper LLC's oil and natural gas reserves and other factors (the "borrowing base") of $775 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, Viper LLC and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. In connection with Viper's fall redetermination in November 2019, the borrowing base under the Viper credit agreement was increased to $775 million. As of December 31, 2019, the borrowing base was $775 million, and Viper LLC had $97 million of outstanding borrowings and $678 million available for future borrowings under the Viper credit agreement. Neither we nor any of our other subsidiaries guarantee the Viper credit agreement.

The outstanding borrowings under the Viper credit agreement bear interest at a per annum rate elected by Viper LLC that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. Viper LLC 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 prepaid 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 Viper and Viper LLC.

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

Financial Covenant	**Required Ratio**
Ratio of total net debt to EBITDAX, as defined in the Viper credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the Viper 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 $1.0 billion 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. The covenant limiting dividends and distributions includes an exception allowing Viper LLC to make distributions if no default, event of default or borrowing base deficiency exists.

As of December 31, 2019, Viper and Viper LLC were in compliance with all financial covenants under the Viper credit agreement, as then in effect. The lenders may accelerate all of the indebtedness under the Viper credit agreement upon the occurrence and during the continuance of any event of default. The Viper credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control.

Viper's Notes

On October 16, 2019, Viper completed an offering in which it issued its 5.375% Senior Notes due 2027 in aggregate principal amount of $500 million. Viper received gross proceeds of $500 million from the such offering, which it loaned to Viper LLC. Viper LLC paid the expenses of the offering, resulting in net proceeds of the offering of $490 million, which Viper LLC used to pay down borrowings under the Viper credit agreement.

The Viper Notes were issued under an indenture, dated as of October 16, 2019, among Viper, as issuer, Viper LLC, as guarantor and Wells Fargo, as trustee, which we refer to as the Viper Indenture. Pursuant to the Viper Indenture and the Viper Notes, interest on the Viper Notes accrues at a rate of 5.375% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2020. The Viper Notes will mature on November 1, 2027.

Viper LLC guarantees the Viper Notes pursuant to the Viper Indenture. Neither we nor any of our other subsidiaries guarantee the Viper Notes.

The Viper Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit Viper's ability and the ability of its restricted subsidiaries to incur or guarantee additional indebtedness or issue certain redeemable or preferred equity, make certain investments, declare or pay dividends or make distributions on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness, transfer or sell assets, agree to payment restrictions affecting its restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens and designate certain of its subsidiaries as unrestricted subsidiaries. These covenants are subject to numerous exceptions, some of which are material. Certain of these covenants are subject to termination upon the occurrence of certain events.

Rattler's Credit Agreement

In connection with the Rattler Offering, Rattler, as parent, and Rattler LLC, as borrower, entered into a credit agreement, dated May 28, 2019, with Wells Fargo Bank, as administrative agent, and a syndicate of banks, as lenders party thereto, which we refer to as the Rattler credit agreement.

The Rattler credit agreement provides for a revolving credit facility in the maximum credit amount of $600 million. Loan principal may be optionally prepaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be prepaid at the maturity date of May 28, 2024. The Rattler credit agreement is guaranteed by Rattler, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC and is secured by substantially all of the assets of Rattler LLC, Rattler, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC. As of December 31, 2019, Rattler LLC had $424 million of outstanding borrowings and $176 million available for future borrowings under the Rattler credit agreement.

The outstanding borrowings under the Rattler credit agreement bear interest at a per annum rate elected by Rattler LLC that is based on the prime rate or LIBOR, in each case plus an applicable margin. The applicable margin ranges from 0.250% to 1.250% per annum for prime-based loans and 1.250% to 2.250% per annum for LIBOR loans, in each case depending on the Consolidated Total Leverage Ratio (as defined in the Rattler credit agreement). Rattler LLC is obligated to pay a quarterly commitment fee ranging from 0.250% to 0.375% per annum on the unused portion of the commitment, which fee is also dependent on the Consolidated Total Leverage Ratio.

The Rattler credit agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, distributions and other restricted payments, transactions with affiliates, and entering into certain swap agreements, in each case of Rattler, Rattler LLC and their restricted subsidiaries. The covenants are subject to exceptions set forth in the Rattler credit agreement, including an exception allowing Rattler LLC or Rattler to issue unsecured debt securities and an exception allowing payment of distributions if no default or events of default exists.

The Rattler credit agreement also contains financial maintenance covenants that require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Consolidated Total Leverage Ratio	Not greater than 5.00 to 1.00 (or not greater than 5.50 to 1.00 for 3 fiscal quarters following certain acquisitions), but if the Consolidated Senior Secured Leverage Ratio (as defined in the Rattler credit agreement) is applicable, then not greater than 5.25 to 1.00)
Consolidated Senior Secured Leverage Ratio commencing with the last day of any fiscal quarter in which the Financial Covenant Election (as defined in the Rattler credit agreement) is made	Not greater than 3.50 to 1.00
Consolidated Interest Coverage Ratio (as defined in the Rattler credit agreement)	Not less than 2.50 to 1.00

For purposes of calculating the financial maintenance covenants prior to the fiscal quarter ending June 30, 2020, EBITDA (as defined in the Rattler credit agreement) will be annualized based on the actual EBITDA for the preceding fiscal quarters starting with the fiscal quarter ending September 30, 2019.

As of December 31, 2019, Rattler and Rattler LLC were in compliance with all financial covenants under the Rattler credit agreement. The lenders may accelerate all of the indebtedness under the Rattler credit agreement upon the occurrence and during the continuance of any event of default. The Rattler credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change in control.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2020 capital budget for drilling, midstream and infrastructure of $2.8 billion to $3.0 billion, representing an increase of 1% over our 2019 capital budget. We estimate that, of these expenditures, approximately:

- $2.45 billion to $2.6 billion will be spent on drilling and completing 320 to 360 gross (288 to 324 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 9,700 feet;
- $200 million to $225 million will be spent on midstream infrastructure, excluding joint venture investments; and
- $150 million to $175 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

During the year ended December 31, 2019, our aggregate capital expenditures for drilling and infrastructure were $2.7 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, 2019, we spent approximately $443 million in cash on acquisitions of leasehold interests and mineral acres.

In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. We repurchased approximately $598 million of our common stock under this program during the year ended December 31, 2019, with approximately $1.4 billion remaining available for future repurchases under this program. We intend to continue to purchase shares under the repurchase program opportunistically with available funds primarily from cash flow from operations and liquidity events such as the sale of assets while maintaining sufficient liquidity to fund our capital expenditure programs.

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 23 drilling rigs including two rigs drilling produced water disposal wells and nine completion crews. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Based upon current oil and natural gas prices and production expectations for 2020, we believe that our cash flow from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2020. 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 2020 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

We monitor and adjust our projected capital expenditures in response to the results of our 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, 2019:

	Payments Due by Period				
	2020	**2021-2022**	**2023-2024**	**Thereafter**	**Total**
			(in millions)		
Secured revolving credit facility[1]	$ —	$ 13	$ —	$ —	$ 13
Commitment fees related to the secured revolving credit facility[2]	2	5	—	—	7
Senior notes	—	420	1,000	2,919	4,339
Interest expense related to the senior notes[3]	168	311	294	301	1,074
DrillCo Agreement	—	—	—	39	39
Viper's secured revolving credit facility[1]	—	97	—	—	97
Commitment fees under Viper's credit agreement[4]	3	4	—	—	7
Viper's senior notes	—	—	—	500	500
Interest expense related to Viper's senior notes	27	54	54	76	211
Rattler's secured revolving credit facility[1]	—	—	424	—	424
Commitment fees under Rattler's credit agreement[5]	—	1	1	—	2
Asset retirement obligations[6]	—	—	—	94	94
Drilling commitments[7]	15	—	—	—	15
Sand supply agreements	18	36	36	23	113
Operating lease obligations[8]	11	14	7	5	37
	$ 244	$ 955	$ 1,816	$ 3,957	$ 6,972

(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) Includes only the minimum amount of commitment fees due which, as of December 31, 2019, includes a commitment fee equal to 0.125% per year of the unused portion of the borrowing base of the Company's credit agreement.
(3) Interest represents the scheduled cash payments on the senior notes and Energen Notes.
(4) Includes only the minimum amount of commitment fees due which, as of December 31, 2019, includes a commitment fee equal to 0.375% per year of the unused portion of the borrowing base of Viper's credit agreement.
(5) Includes only the minimum amount of commitment fees due which, as of December 31, 2019, includes a commitment fee equal to 0.250% per year of the unused portion of the borrowing base of Rattler's credit agreement.
(6) 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 8—Asset Retirement Obligations of the Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

(7) Drilling commitments represent future minimum expenditure commitments for drilling rig services under contracts to which the Company was a party on December 31, 2019.

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

The table above does not include estimated deficiency fees related to certain volume commitments that we have as they are based off future volume deliveries and differences from market pricing which we cannot predict.

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.

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.

Midstream Revenue

Substantially all revenues from gathering, compression, water handling, disposal and treatment operations are derived from intersegment transactions for services 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 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 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 obligations under any of our product sales contracts.

The majority of our midstream revenue agreements have a term greater than one year, and as such we have 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. We have 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 ASC 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 year ended December 31, 2019, 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 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, 2019 and 2018. 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 12—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 period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

Recent Accounting Pronouncements

For information regarding recent accounting pronouncements, See Note 2—Summary of Significant Accounting Policies included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K.

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, 2019 and 2018. 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, 2019. Please read Note 18—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, double-up swaps, put spreads, interest rate 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 West Texas Intermediate pricing (Cushing and Magellan East Houston) and Crude Oil - Brent and with natural gas derivative settlements based on NYMEX Henry Hub and Waha Hub pricing.

At December 31, 2019 and December 31, 2018, we had a net asset derivative position of $26 million and $216 million, respectively, 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, 2019, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to a net liability position of $178 million, a decrease of $204 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $232 million, an increase of $206 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 $186 million at December 31, 2019) and receivables from the sale of our oil and natural gas production (approximately $429 million at December 31, 2019).

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, 2019, three purchasers each accounted for more than 10% of our revenue: Shell (27%); Plains (23%); and Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of our revenue: Shell (26%); Koch (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 (31%); Koch (19%); and Enterprise Crude Oil LLC (11%). 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, 2019, we had 15 customers that represented approximately 80% of our total joint operations receivables. At December 31, 2018, we had four customer that represented approximately 82% 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 outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal an alternate 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 0.125% to 1.0% per annum and from 1.125% to 2.0% per annum in the case of LIBOR, in each case, depending on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt. We are obligated to pay a quarterly commitment fee ranging from 0.125% to 0.350% per year on the unused portion of the commitment, based on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt.

As of December 31, 2019, we had $13 million borrowings outstanding under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 3.20% on December 31, 2019. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $130,000 based on the $13 million outstanding in the aggregate under our revolving credit facility as of such date.

As of December 31, 2019, Viper LLC had $97 million in outstanding borrowings. Viper LLC's weighted average interest rate was 4.30%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in Viper LLC's interest expense of approximately $1 million based on the $97 million outstanding in the aggregate under the Viper credit agreement on December 31, 2019.

As of December 31, 2019, Rattler LLC had $424 million of outstanding borrowings. Rattler LLC's weighted average interest rate was 2.98%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in Rattler LLC's interest expense of approximately $4 million based on the $424 million outstanding under the Rattler credit agreement as of December 31, 2019.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

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

As of December 31, 2019, 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, 2019, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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, 2019.

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, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting at December 31, 2019, is included in this Item under the heading “Report of Independent Registered Public Accounting Firm.”

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, 2019, 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, 2019, 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, 2019, and our report dated February 26, 2020 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.

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 26, 2020

ITEM 9B. OTHER INFORMATION

Senior Management Severance Plan

Effective February 20, 2020, we adopted the Diamondback Energy, Inc. Senior Management Severance Plan, or the Severance Plan, and have entered into a participation agreement thereunder with each of our named executive officers. Pursuant to the participation agreements, the benefits under the Severance Plan replace the employment agreements with each of our named executive officers. The Severance Plan also covers other eligible executives who are selected to participate and replaces any employment agreement they may have.

Payments and Benefits Unrelated to a Change in Control. In the event that the employment of a participating executive is terminated by us other than for "cause" (and not by reason of death or disability) or if the participant terminates his or her employment for "good reason" (in each case as defined in the Severance Plan), in addition to any accrued but unpaid base salary or unreimbursed business expenses payable in accordance with the requirements of applicable law, the participant is entitled to receive severance benefits consisting of:

(i) an amount, if any, equal to the bonus that would be payable for services attributable to a completed prior year performance period that has not been paid under the terms of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan;

(ii) a multiple of base salary continuation for a specified number of months (2x for 24 months for the Chief Executive Officer, 1x for 18 months for Executive Vice-Presidents, 1x for 15 months for Senior Vice-Presidents and 1x for 12 months for Vice-Presidents);

(iii) a pro-rated target annual cash bonus for the year of termination (based on the number of days employed during the year of termination);

(iv) up to 18 months of Company-paid COBRA coverage; and

(v) the vesting or forfeiture, as applicable, of each outstanding unvested equity-based compensation award granted by us or our affiliates in accordance with the terms of the applicable equity award agreement. Mr. Stice's participation agreement includes terms that are intended to maintain certain benefits under his prior employment agreement and are consistent with prior public disclosure that require each equity award granted to Mr. Stice to become 100% vested upon an eligible termination, and in the case of outstanding performance based equity awards to vest at the maximum level under the equity award agreement, and be settled within ten business days.

Severance Benefits Related to a Change in Control). In the event that employment of a participant is terminated by us other than for "cause" (and not by reason of death or disability) or if the participant terminates his or her employment for "good reason," in either case within the two year period immediately following a change in control (as defined in the Severance Plan), the participant will be entitled to the benefits described above, except that the salary continuation described in clause (ii) will be replaced by a lump sum cash payment equal to a multiple of the participant's base salary plus such participant's average bonus for the preceding three years (3.0x for the Chief Executive Officer, 2.5x for Executive Vice-Presidents, 2.25x for Senior Vice-Presidents and 2.0x for Vice-Presidents).

Severance Benefits Related to Death or Disability. The Severance Plan also provides the same benefits described in clauses (i), (ii) and (iii) (but not clause (iv)) in the event that a participant dies or becomes disabled (as defined in the Severance Agreement) while employed by us. Mr. Stice's participation agreement includes terms that are intended to maintain certain benefits under his prior employment agreement and are consistent with prior public disclosure that require the Company to pay 100 percent of the premiums to continue his, his spouse's and any of his eligible dependents' group health plan continuation coverage under COBRA.

Release and Restrictive Covenants. The payment of any benefits under the Severance Plan is conditioned on the participant's (or if applicable, the participant's personal representative's or estate's) execution of a general release of claims. The Severance Plan also includes certain restrictive covenants that continue beyond the employment period, including non-competition and non-solicitation obligations for a period of one year following termination of employment. If a participating executive terminates employment on a basis that is not eligible for severance benefits, we can elect to apply the restrictive covenants for up to 12 months and receive a release by payment of an amount equal to one-twelfth of the participant's annualized base salary plus target annual bonus for each month the restrictive covenants will apply.

We believe that these severance benefits provide the same type of income transition protections that were provided to our executives under their prior employment agreements. These arrangements are intended to attract and retain qualified executives that could have job alternatives that may appear to them to be less risky absent these arrangements. We believe that the enhanced severance benefits resulting from terminations related to a change in control transaction are in the interest of our stockholders because they provide an incentive for executives to continue to help successfully execute such a transaction from its early stages through consummation. We also believe that these benefits provide important protection to our named executive officers, are consistent with the prior employment protections and the practices of peer group companies and are appropriate for the attraction and retention of executive talent.

Appointment of Executive Vice President-Operations

On February 20, 2020, our board of directors promoted Daniel N. Wesson to serve as our Executive Vice President-Operations, effective March 1, 2020. Until the effective date of this promotion, Mr. Wesson will continue to serve as our Senior Vice President of Operations, a position he has held since February 2019. Mr. Wesson served as our Vice President of Operations from April 2017 to February 2019 and as our Completions Manager from January 2013 to April 2017. He joined us as an Operations Engineer in February 2012. Before joining our company, Mr. Wesson served in various operations and engineering roles for BOPCO L.P. from 2010 to 2012 and ConocoPhillips from 2007 to 2010. Mr. Wesson received his Bachelor of Science degree in Mechanical Engineering from Louisiana State University and is a member of the Permian Basin Society of Petroleum Engineers.

In his role as our Executive Vice President-Operations, Mr. Wesson is entitled to receive an annual base salary and participate in (i) our annual executive cash incentive program, which provides an opportunity to receive an annual bonus, based on a target percentage of the annual base salary and pre-established performance goals, (ii) our equity incentive plan, under which we grant annual performance-based and time-vesting equity awards, (iii) the Severance Plan described above and (iv) any other employee benefit plans generally available to similarly situated employees of our company, as in effect from time to time.

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, 2019.

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, 2019.

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, 2019.

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, 2019.

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, 2019.

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#	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*	Description of the Company's Securities.
4.2	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).
4.3	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).
4.4	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).
4.5	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 (incorporated by reference to Exhibit 4.8 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).

3. Exhibits

Exhibit Number	Description
4.6	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 (incorporated by reference to Exhibit 4.9 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).
4.7	Indenture, dated as of December 5, 2019, between Diamondback Energy, Inc. 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 December 5, 2019).
4.8	First Supplemental Indenture, dated as of December 5, 2019, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the form of 2024 Notes, 2026 Notes and 2029 Notes) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 5, 2019).
4.9	Indenture, dated as of October 16, 2019, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor, and Wells Fargo Bank, National Association, as trustee (including the form of Viper Energy Partners LP's 5.375% Senior Notes due 2027) (incorporated by reference to Exhibit 4.1 of Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.10	Consent Letter, dated August 28, 2019, between 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 of the Company's Current Report on Form 8-K (File 001-35700) filed on September 4, 2019).
4.11	Subordinated Promissory Note, dated as of October 16, 2019, by Viper Energy Partners LLC in favor of Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.12	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).
4.13	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).
4.14	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+*	2020 Form of Time Vesting Restricted Stock Unit Award Agreement.
10.3+*	2020 Form of Performance Vesting Restricted Stock Unit Award Agreement.
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+*	Diamondback Energy, Inc. Senior Management Severance Plan (including forms of participation agreements attached thereto as Schedules C-1 and C-2).
10.6+	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).
10.7+	2014 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).
10.8+	2014 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).
10.9+	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).
10.10	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).

3. Exhibits

Exhibit Number	Description
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	Tenth Amendment to Second Amended and Restated Credit Agreement, dated as of March 25, 2019, between Diamondback, 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. 00 1-35700), filed by the Company with the SEC on March 29, 2019).
10.19	Eleventh Amendment to Second Amended and Restated Credit Agreement, dated as of June 28, 2019, between 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 July 3, 2019).
10.20	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).
10.21	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).

3. Exhibits

Exhibit Number	Description
10.22	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of Viper Energy Partners LP's Form 8-K (File 001-36505) filed on September 30, 2019).
10.23	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of Viper Energy Partners LP's Form 8-K (File 001-36505) filed on October 10, 2019).
10.24	Credit Agreement, dated May 28, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.2 to Rattler Midstream LP's Form 8-K, File No. 001-38919, filed by Rattler Midstream LP with the SEC on May 29, 2019).
10.25	First Amendment to the Credit Agreement, dated as of October 23, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 of Rattler Midstream LP's Form 8-K (File 001-38919) filed on October 28, 2019).
10.26	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).
10.27+	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).
10.28+	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).
10.29+	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).
10.30+	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).
10.31+	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).
10.32+	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.
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 10, 2020, 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, 2019.

3. Exhibits

Exhibit Number	Description
99.2*	Report of Ryder Scott Company, L.P., dated January 10, 2020, 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, 2019.
101	The following financial information from the Company’s Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statement of Changes in Stockholders’ Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

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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.

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 26, 2020

/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 26, 2020
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2020
/s/ Michael P. Cross Michael P. Cross	Director	February 26, 2020
/s/ David L. Houston David L. Houston	Director	February 26, 2020
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 26, 2020
/s/ Melanie M. Trent Melanie M. Trent	Director	February 26, 2020
/s/ Kaes Van’t Hof Kaes Van’t Hof	Chief Financial Officer and Executive Vice President—Business Development (Principal Financial Officer)	February 26, 2020
/s/ Teresa L. Dick Teresa L. Dick	Chief Accounting Officer, Executive Vice President and Assistant Secretary (Principal Accounting Officer)	February 26, 2020

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, 2019 and 2018, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 26, 2020 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.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depletion expense, impairment evaluation and acquisition of oil and gas properties

As described in Note 2 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future revenues to record depletion expense and measure its oil and gas properties for potential impairment. Additionally, as described in Note 3 to the financial statements, the Company acquired significant oil and gas properties throughout the year. To estimate the volume of proved reserves and future revenues, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties, forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties, and for acquisitions that included proved developed producing properties using an estimated fair value pricing model for the valuation of proved producing reserves. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment measurements. We identified the estimation of proved reserves of oil and gas properties, due to its impact on depletion expense, impairment evaluation and acquisition valuation of oil and gas properties, as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.
Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of key controls relating to the preparation of the ceiling test calculation, management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and gas properties for potential impairment, and management's estimation of the fair value of acquired oil and gas properties. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company's accounting records and the management review controls on information provided to the reservoir engineering specialists and the management review controls on the final proved reserve report prepared by the Company's specialists.

- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.

- For acquisitions of oil and gas properties during the year in which proved developed producing properties are significant and to the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, such as historical pricing differentials, working and net revenue interests and future capital expenditures and operating costs, we tested management's process for determining the assumptions, including examining the underlying support. Specifically, our audit procedures involved testing management's assumptions as follows:
  - Analyzed the appropriateness of fair value pricing used in the acquisition reserve report to published product pricing on the acquisition closing date;
  - Analyzed the appropriateness of the future operating cost and capital expenditure assumptions used in the acquisition reserve report to historical operating costs and capital expenditures of similarly located properties
  - Evaluated the working and net revenue interests used in the acquisition reserve report by inspecting a sample of land and division order records;
  - Analyzed, on a sample basis, the appropriateness of management's estimated future production volumes and the production decline curves; and
  - Utilized valuation specialists to compare the acreage value allocated, on a per acre basis, to undeveloped properties and to other recent acquisitions in the same or similar locations.

- To the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs and working and net revenue interests, we tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management's assumptions as follows:
  - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
  - Evaluated the models used to estimate the operating costs at year-end compared to historical operating costs;
  - Compared the models used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells with similar locations;
  - Evaluated the working and net revenue interests used in the reserve report by inspecting a sample of land and division order records;
  - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the operator's intent to develop the proved undeveloped properties;
  - Evaluated the estimated ultimate recovery of proved undeveloped properties to the estimated ultimate recovery of comparable proved developed producing properties; and
  - Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
February 26, 2020

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2019	December 31, 2018
	(In millions, except share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 123	$ 215
Restricted cash	5	—
Accounts receivable:		
Joint interest and other, net	186	96
Oil and natural gas sales	429	296
Inventories	37	37
Derivative instruments	46	231
Prepaid expenses and other	43	50
Total current assets	869	925
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($9,207 million and $9,670 million excluded from amortization at December 31, 2019 and 2018, respectively)	25,782	22,299
Midstream assets	931	700
Other property, equipment and land	125	147
Accumulated depletion, depreciation, amortization and impairment	(5,003)	(2,774)
Net property and equipment	21,835	20,372
Equity method investments	479	1
Derivative instruments	7	—
Deferred tax asset	142	97
Investment in real estate, net	109	116
Other assets	90	85
Total assets	$ 23,531	$ 21,596
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 179	$ 128
Accrued capital expenditures	475	495
Other accrued liabilities	304	253
Revenues and royalties payable	278	143
Derivative instruments	27	—
Total current liabilities	1,263	1,019
Long-term debt	5,371	4,464
Derivative instruments	—	15
Asset retirement obligations	94	136
Deferred income taxes	1,886	1,785
Other long-term liabilities	11	10
Total liabilities	$ 8,625	$ 7,429

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets - Continued

	December 31,	
	2019	2018
	(In millions, except share amounts)	
Commitments and contingencies (Note 18)		
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 159,002,338 issued and outstanding at December 31, 2019; 200,000,000 shares authorized, 164,273,447 issued and outstanding at December 31, 2018	$ 2	$ 2
Additional paid-in capital	12,357	12,936
Retained earnings	890	762
Total Diamondback Energy, Inc. stockholders' equity	13,249	13,700
Non-controlling interest	1,657	467
Total equity	14,906	14,167
Total liabilities and equity	$ 23,531	$ 21,596

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2019	2018	2017
	(In millions, except per share amounts, shares in thousands)		
Revenues:			
Oil sales	$ 3,554	$ 1,879	$ 1,044
Natural gas sales	66	61	52
Natural gas liquid sales	267	190	90
Lease bonus	4	3	12
Midstream services	64	34	7
Other operating income	9	9	—
Total revenues	3,964	2,176	1,205
Costs and expenses:			
Lease operating expenses	490	205	127
Production and ad valorem taxes	248	133	74
Gathering and transportation	88	26	13
Midstream services	91	72	10
Depreciation, depletion and amortization	1,447	623	327
Impairment of oil and natural gas properties	790	—	—
General and administrative expenses	104	65	48
Asset retirement obligation accretion	7	2	1
Merger and integration expense	—	36	—
Other operating expense	4	3	—
Total costs and expenses	3,269	1,165	600
Income from operations	695	1,011	605
Other income (expense):			
Interest expense, net	(172)	(87)	(41)
Other (expense) income, net	(2)	89	11
(Loss) gain on derivative instruments, net	(108)	101	(78)
Gain (loss) on revaluation of investment	5	(1)	—
Loss on extinguishment of debt	(56)	—	—
Total other income (expense), net	(333)	102	(108)
Income before income taxes	362	1,113	497
Provision for (benefit from) income taxes	47	168	(20)
Net income	315	945	517
Net income attributable to non-controlling interest	75	99	35
Net income attributable to Diamondback Energy, Inc.	$ 240	$ 846	$ 482
Earnings per common share:			
Basic	$ 1.47	$ 8.09	$ 4.95
Diluted	$ 1.47	$ 8.06	$ 4.94
Weighted average common shares outstanding:			
Basic	163,493	104,622	97,458
Diluted	163,843	104,929	97,688
Dividends declared per share	$ 0.9375	$ 0.5000	$ —

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	($ in millions, shares in thousands)					
Balance December 31, 2016	90,144	$ 1	$ 4,216	$ (520)	$ 321	$ 4,018
Net proceeds from issuance of common units - Viper Energy Partners LP					370	370
Unit-based compensation					2	2
Common units issued for acquisition					3	3
Stock-based compensation			32			32
Distribution to non-controlling interest					(41)	(41)
Common shares issued for Brigham	7,686		809			809
Exercise of stock options and vesting of restricted stock units	337					—
Change in ownership of consolidated subsidiaries, net			234		(363)	(129)
Net income				482	35	517
Balance at December 31, 2017	98,167	1	5,291	(38)	327	5,581
Impact of adoption of ASU 2016-01, net of tax				(9)	(7)	(16)
Net proceeds from issuance of common units - Viper Energy Partners LP					303	303
Unit-based compensation					3	3
Stock-based compensation			34			34
Common shares issued for business combination	63,126	1	7,069			7,070
Stock options assumed in business combination			14			14
Restricted stock units assumed in business combination			52			52
Repurchased shares for tax withholding	(140)		(14)			(14)
Distribution to non-controlling interest					(98)	(98)
Common shares issued for Ajax	2,584		340			340
Dividend paid				(37)		(37)
Exercise of stock options and vesting of restricted stock units	536					—
Change in ownership of consolidated subsidiaries, net			150		(160)	(10)
Net income				846	99	945
Balance December 31, 2018	164,273	2	12,936	762	467	14,167
Net proceeds from issuance of common units - Viper Energy Partners LP					341	341
Net proceeds from issuance of common units - Rattler Midstream LP					720	720
Unit-based compensation					7	7
Common units issued for acquisition		—	—		124	124
Stock-based compensation			57			57
Repurchased shares for tax withholding	(125)		(13)			(13)
Repurchased shares for share buyback program	(6,385)		$ (598)			$ (598)
Distribution to non-controlling interest					$ (122)	$ (122)

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	($ in millions, shares in thousands)					
Dividend paid				(112)		(112)
Exercise of stock and unit options and awards of restricted stock	1,239		8			8
Change in ownership of consolidated subsidiaries, net			(33)		45	12
Net income				240	75	315
Balance December 31, 2019	159,002	$ 2	$ 12,357	$ 890	$ 1,657	$ 14,906

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Cash flows from operating activities:			
Net income	$ 315	$ 945	$ 517
Adjustments to reconcile net income to net cash provided by operating activities:			
Provision for (benefit from) deferred income taxes	47	168	(20)
Impairment of oil and natural gas properties	790	—	—
Asset retirement obligation accretion	7	2	1
Depreciation, depletion and amortization	1,447	623	327
Amortization of debt issuance costs	9	12	4
Loss on early extinguishment of debt	56	—	—
Change in fair value of derivative instruments	188	(222)	84
Loss (income) from equity investment	6	—	(1)
(Gain) loss on revaluation of investment	(5)	1	—
Equity-based compensation expense	48	27	26
(Gain) loss on sale of assets, net	(1)	3	(1)
Gain on sale of inventory	(1)	—	—
Restricted cash	(5)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(187)	13	(97)
Inventories	(10)	(14)	(2)
Prepaid expenses and other	29	25	(11)
Accounts payable and accrued liabilities	(129)	(7)	37
Income tax payable	—	(1)	1
Accrued interest	(5)	(22)	(21)
Revenues and royalties payable	135	12	45
Net cash provided by operating activities	2,734	1,565	889
Cash flows from investing activities:			
Drilling, completions and non-operated additions to oil and natural gas properties	(2,557)	(1,359)	(737)
Infrastructure additions to oil and natural gas properties	(120)	(102)	(56)
Additions to midstream assets	(244)	(204)	(68)
Purchase of other property, equipment and land	(5)	(7)	(23)
Acquisition of leasehold interests	(443)	(1,371)	(1,961)
Acquisition of mineral interests	(333)	(440)	(407)
Acquisition of midstream assets	—	—	(50)
Proceeds from sale of assets	300	80	66
Investment in real estate	(1)	(111)	—
Funds held in escrow	—	11	104
Equity investments	(485)	—	—
Net cash used in investing activities	(3,888)	(3,503)	(3,132)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	2,350	2,652	754
Repayment under credit facility	(3,718)	(1,242)	(384)
Repayment on Energen's credit facility	—	(559)	—
Proceeds from senior notes	3,469	1,062	—
Repayment of senior notes	(1,250)	—	—
Proceeds from joint venture	$ 39	$ —	$ —

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

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Premium on extinguishment of debt	$ (44)	$ —	$ —
Debt issuance costs	(18)	(25)	(9)
Public offering costs	(41)	(3)	(1)
Proceeds from public offerings	1,106	305	370
Proceeds from exercise of stock options	9	—	—
Repurchased shares for tax withholdings	(13)	(14)	—
Repurchased as part of share buyback	(593)	—	—
Dividends to stockholders	(112)	(37)	—
Distributions to non-controlling interest	(122)	(98)	(41)
Net cash provided by financing activities	1,062	2,041	689
Net (decrease) increase in cash and cash equivalents	(92)	103	(1,554)
Cash and cash equivalents at beginning of period	215	112	1,666
Cash and cash equivalents at end of period	$ 123	$ 215	$ 112
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 237	$ 114	$ 58
Cash paid for income taxes	$ —	$ 1	$ —
Supplemental disclosure of non-cash transactions:			
Change in accrued capital expenditures	$ (20)	$ 274	$ 161
Capitalized stock-based compensation	$ 17	$ 10	$ 9
Common stock issued for Ajax	$ —	$ 340	$ —
Common stock issued for Brigham	$ —	$ —	$ 809
Common stock issued for business combination(1)	$ —	$ 7,136	$ —
Asset retirement obligations acquired	$ 4	$ 111	$ 2

(1) Includes $7 billion of Common stock issued for business combination, $14 million for stock options assumed and $52 million 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.

The wholly-owned subsidiaries of Diamondback, as of December 31, 2019, 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 ("Viper's General Partner"), Rattler Midstream GP LLC, a Delaware limited liability company (Rattler's General Partner), and Energen Corporation, an Alabama corporation ("Energen"). The consolidated subsidiaries include these wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership ("Viper"), Viper's subsidiary Viper Energy Partners LLC, a Delaware limited liability company ("Viper LLC"), Rattler Midstream LP (formerly known as Rattler Midstream Partners LP), a Delaware limited partnership ("Rattler"), Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC), a Delaware limited liability company ("Rattler LLC"), Rattler LLC's wholly-owned subsidiary Tall City Towers LLC, a Delaware limited liability company ("Tall City"), and Energen's wholly-owned subsidiaries Energen Resources Corporation, an Alabama corporation ("Energen Resources"), and EGN Services, Inc., an Alabama corporation.

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.

Viper is consolidated in the financial statements of the Company. As of December 31, 2019, the Company owned approximately 58% of the total units outstanding of Viper and the Company's wholly owned subsidiary, Viper Energy Partners GP LLC, is Viper's General Partner.

Rattler is consolidated in the financial statements of the Company. As of December 31, 2019, the Company owned approximately 71% of the total units outstanding of Rattler. The Company's wholly-owned subsidiary, Rattler Midstream GP LLC, is Rattler's General Partner.

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.

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

As of December 31, 2019, the Company had restricted cash of $5 million related to the Company's obligations under its participation and development agreement with Obsidian Resources, L.L.C.

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, 2019 and 2018, the Company recorded an allowance for doubtful accounts of $2 million related to joint interest receivables.

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).

Prepaid Expenses and Other

Prepaid expenses and other consist of the following:

	Year Ended December 31,	
	2019	2018
	(In millions)	
Prepaid insurance	$ 6	$ 4
Prepaid fees and licenses	4	3
Income tax receivable	19	38
Other	14	5
Total prepaid expenses and other	$ 43	$ 50

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 9–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 $13.54, $12.62 and $11.11 for the years ended December 31, 2019, 2018 and 2017, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $1.4 billion, $595 million and $321 million for the years ended December 31, 2019, 2018 and 2017, 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. An impairment on proved oil and natural gas properties of $790 million was recorded for the year ended December 31, 2019. 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.

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 15 years. Depreciation expense for other property and equipment was $16 million, $9 million and $1 million for the years ended December 31, 2019, 2018 and 2017, 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.

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, 2019, 2018 and 2017, 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 $66 million, $32 million and $22 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Inventories

Inventories are stated at the lower of cost or market and consist of tubular goods and equipment at December 31, 2019 and 2018. 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, 2019, 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 $36 million and $28 million, net of accumulated amortization of $15 million and $9 million, as of December 31, 2019 and 2018, respectively. Long-term debt included capitalized costs related to the senior notes of $24 million and $32 million, net of accumulated amortization of $14 million and $15 million, as of December 31, 2019 and 2018, 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,	
	2019	**2018**
	(In millions)	
Liability for drilling costs prepaid by joint interest partners	$ 12	$ 16
Interest payable	27	26
Lease operating expenses payable	119	59
Ad valorem taxes payable	68	49
Other	78	103
Total other accrued liabilities	$ 304	$ 253

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 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 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 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 obligations 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 the Company 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. The Company 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 ASC 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 year ended December 31, 2019, 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, 2019, 2018 and 2017.

For additional information on the Company’s investments, see Note 9—Equity Method Investments.

Accounting for Equity-Based Compensation

The Company has granted various types of stock-based awards including stock options and restricted stock units. Viper has granted various unit-based awards including unit options and phantom units to employees, officers and directors of Viper's General Partner and the Company who perform services for Viper. Rattler has granted unit-based awards consisting of phantom units to employees, officers and directors of Rattler's General Partner and the Company who perform services for Rattler. These plans and related accounting policies are defined and described more fully in Note 12—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, 2019, three purchasers each accounted for more than 10% of our revenue: Shell (27%); Plains (23%); and Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of the Company's revenue: Shell (26%); Koch (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 (31%); Koch (19%); and Enterprise Crude Oil LLC (11%). 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, 2019, 2018 and 2017, the Company had no margin tax expense. The Company's 2015, 2016, 2017, 2018 and 2019 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2019 and 2018, we had $2 million unrecognized tax benefits. 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, 2019, 2018 and 2017, there was no interest or penalties associated with uncertain tax positions recognized in the Company's consolidated financial statements.

Recent Accounting Pronouncements

The Company considers the applicability and impact of all ASUs. ASUs not listed below were assessed and determined to be either not applicable or clarifications of ASUs previously disclosed. The following table provides a brief description of recent accounting pronouncements and the Company's analysis of the effects on its financial statements:

Standard	Description	Date of Adoption	Effect on Financial Statements or Other Significant Matters
Recently Adopted Pronouncements			
ASU 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.	Q1 2020	The Company adopted this update effective January 1, 2020. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity since it does not have a history of credit losses.
ASU 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.	Q1 2020	The Company adopted this update effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity since it does not have transfers between fair value levels.
ASU 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.	Q1 2020	The Company adopted this update prospectively effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.
ASU 2019-05, "Financial Instruments-Credit Losses (Topic 326)"	This update allows a fair value option to be elected for certain financial assets, other than held-to-maturity debt securities, that were previously required to be measured at amortized cost basis.	Q1 2020	The Company adopted this update effective January 1, 2020. The adoption of this update did not have an impact on its financial position, results of operations or liquidity since it does not have any cost method investments.
Pronouncements Not Yet Adopted			
ASU 2019-12, "Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes"	This update is intended to simplify the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance.	Q1 2021	This update is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Company does not believe that the adoption of this update will have an impact on its financial position, results of operations or liquidity.

3. ACQUISITIONS AND DIVESTITURES

2019 Activity

Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

On May 23, 2019, the Company completed its divestiture of 6,589 net acres of certain non-core Permian assets, which were acquired by the Company in its merger with Energen (as described below), for an aggregate sale price of $37 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company's reserve base or depreciation, depletion and amortization rate.

On July 1, 2019, the Company completed its divestiture of 103,750 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in the merger with Energen (as described below), for an aggregate sale price of $285 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company's reserve base or depreciation, depletion and amortization rate.

2019 Drop-Down Transaction

On July 29, 2019, the Company entered into a definitive purchase agreement to divest certain mineral and royalty interests to Viper for approximately 18.3 million of Viper's newly-issued Class B units, approximately 18.3 million newly-issued units of Viper LLC with a fair value of $497 million and $190 million in cash, after giving effect to closing adjustments for net title benefits (the "Drop-Down"). The mineral and royalty interests divested in the Drop-Down represent approximately 5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by the Company, and have an average net royalty interest of approximately 3.2% (the "Drop-Down Assets"). The Drop-Down closed on October 1, 2019 and was effective as of July 1, 2019. Viper funded the cash portion of the purchase price of the Drop-Down Assets through a combination of cash on hand and borrowings under Viper LLC's revolving credit facility.

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 $110 million.

Ajax Resources, LLC

On October 31, 2018, the Company completed its acquisition of leasehold interests and related assets of Ajax Resources, LLC, which included approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900 million in cash and approximately 2.6 million shares of the Company's common stock (the "Ajax acquisition"). This transaction 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 (described below under the caption "2018 Drop-Down Transaction"), 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 10—Debt for information relating to this offering.

2018 Drop-down Transaction

On August 15, 2018, the Company completed a transaction to sell 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 the Company, for $175 million.

ExL Petroleum Management, LLC and EnergyQuest II LLC

On October 31, 2018, the Company completed its acquisitions of 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 $313 million in cash. These transactions were effective as of August 1, 2018 and were funded through a combination of cash on hand, proceeds from the sale of assets to Viper (described immediately above) and borrowing under the Company's revolving credit facility.

Energen Corporation Merger

On November 29, 2018, the Company completed its acquisition of Energen in an all-stock transaction (the " Merger"), which was accounted for as a business combination. Upon completion of the Merger, 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 10—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 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 resulting in no goodwill or bargain purchase gain.

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

	(In millions)
Consideration:	
Fair value of the Company's common stock issued	$ 7,136
Total consideration	$ 7,136
Fair value of liabilities assumed:	
Current liabilities	$ 388
Asset retirement obligation	105
Long-term debt	1,099
Noncurrent derivative instruments	17
Deferred income taxes	1,425
Other long-term liabilities	7
Amount attributable to liabilities assumed	$ 3,041
Fair value of assets acquired:	
Total current assets	$ 298
Oil and natural gas properties	9,361
Midstream assets	253
Investment in real estate	11
Other property, equipment and land	58
Asset retirement obligation	105
Other postretirement assets	3
Noncurrent income tax receivable, net	76
Other long term assets	12
Amount attributable to assets acquired	$ 10,177

The Company has included in its consolidated statements of operations revenues of $102 million and direct operating expenses of $17 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 $37 million for the year ended December 31, 2018 and acquisition-related costs incurred by Energen of $59 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.

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 millions, except per share amounts)	
Revenues	$ 3,532	$ 2,196
Income from operations	1,559	900
Net income	1,320	875
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 $1.7 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 $48 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 millions)
Proved oil and natural gas properties	$ 386
Unevaluated oil and natural gas properties	2,123
Midstream assets	47
Prepaid capital costs	4
Oil inventory	1
Revenues and royalties payable	(10)
Asset retirement obligations	(2)
Total fair value of net assets	$ 2,549

The Company has included in its consolidated statements of operations revenues of $81 million and direct operating expenses of $24 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.

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 millions, except per share amounts)	
Revenues	$ 1,228	$ 627
Income (loss) from operations	619	(13)
Net income (loss)	473	(109)
Basic earnings per common share	$ 4.85	$ (1.45)
Diluted earnings per common share	$ 4.84	$ (1.45)

4. VIPER ENERGY PARTNERS LP

Viper is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "VNOM". Viper was formed by Diamondback on February 27, 2014, to, among other things, own, acquire and exploit oil and natural gas properties in North America. Viper 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, Viper. As of December 31, 2019, the Company owned approximately 58% of Viper's total units outstanding.

During the year ended December 31, 2019, Diamondback received distributions of $133 million in respect of its interests in Viper and Viper LLC.

Viper completed the following equity offerings during the years ended December 31, 2019, 2018 and 2017:

Date	Number of Units of Common Units Sold	Number of Units of Common Units Issued to Underwriters	Proceeds Received by Viper	Amount Repaid on Viper LLC's Credit Facility
			(in millions)	
January 2017	9,775,000	1,275,000	$ 148	$ 121
July 2017(1)	16,100,000	2,100,000	$ 232	$ 153
July 2018	10,080,000	1,080,000	$ 303	$ 362
March 2019	10,925,000	1,425,000	$ 341	$ 314

(1) 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.

As a result of Viper's public offerings, Viper's issuance of units for acquisitions and Viper's issuance of unit-based compensation, the Company's ownership percentage in Viper was reduced. During the year ended December 31, 2019, the Company recorded a $45 million decrease to non-controlling interest in Viper with an increase to additional paid-in capital, which represents the difference between the Company's share of the underlying net book value in Viper 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, Viper announced that the Board of Directors of the 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 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 Viper the 73,150,000 common units the Company 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 (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 the Company owned the remaining approximately 64% of the outstanding units issued by the Operating Company. Upon completion of Viper'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 Viper's Class B units owned by the Company are exchangeable from time to time for Viper'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 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 million to Viper in respect of its general partner interest and (ii) the Company made a cash capital contribution of $1 million to Viper 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 Viper and a cash amount of $10,000 representing a proportionate return of the $1 million invested capital in respect of the Class B units. The General Partner continues to serve as Viper's general partner and the Company continues 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 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.

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 "Viper Partnership Agreement"), requires Viper to reimburse Viper's General Partner for all direct and indirect expenses incurred or paid on Viper's behalf and all other expenses allocable to Viper or otherwise incurred by Viper's General Partner in connection with operating Viper's business. The Viper Partnership Agreement does not set a limit on the amount of expenses for which Viper's 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 Viper or on its behalf and expenses allocated to Viper's General Partner by its affiliates. Viper's General Partner is entitled to determine the expenses that are allocable to Viper. For each of the year ended December 31, 2019 and 2018, Viper's General Partner allocated $3 million and $2 million, respectively, to Viper.

Tax Sharing

In connection with the closing of the Viper Offering, Viper entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which Viper agreed to reimburse Diamondback for its share of state and local income and other taxes for which Viper'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 Viper 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 Viper may be a member for this purpose, to owe less or no tax. In such a situation, Viper agreed to reimburse Diamondback for the tax Viper would have owed had the tax attributes not been available or used for Viper's benefit, even though Diamondback had no cash tax expense for that period. For the year ended December 31, 2019, Viper did not accrue any state income tax expense. For the year ended December 31, 2018, Viper accrued a minimal amount for its share of Texas margin tax for which Viper's results are included in a combined tax return filed by Diamondback.

Viper LLC's Revolving Credit Facility

Viper 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 10—Debt for a description of this credit facility.

5. RATTLER MIDSTREAM LP

Rattler is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "RTLR". Rattler was formed by Diamondback in July 2018 to own, operate, develop and acquire midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Rattler's General Partner, a wholly-owned subsidiary of Diamondback, serves as the general partner of Rattler. As of December 31, 2019, Diamondback owned approximately 71% of Rattler's total units outstanding.

Prior to the completion of Rattler's initial public offering (the "Rattler Offering") in May of 2019, Diamondback owned all of the general and limited partner interests in Rattler. The Rattler Offering consisted of 43,700,000 common units representing approximately 29% of the limited partner interests in Rattler at a price to the public of $17.50 per common unit, which included 5,700,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms which closed on May 30, 2019. Rattler received net proceeds of approximately $720 million from the sale of these common units, after deducting offering expenses and underwriting discounts and commissions.

In connection with the completion of the Rattler Offering, Rattler (i) issued 107,815,152 Class B Units representing an aggregate 71% voting limited partner interest in Rattler in exchange for a $1 million cash contribution from Diamondback, (ii) issued a general partner interest in Rattler to Rattler's General Partner, in exchange for a $1 million cash contribution from Rattler's General Partner, and (iii) caused Rattler LLC to make a distribution of approximately $727 million to Diamondback. Diamondback, as the holder of the Class B units, and Rattler's General Partner, as the holder of the general partner interest, are entitled to receive cash preferred distributions equal to 8% per annum on the outstanding amount of their respective $1 million capital contributions, payable quarterly.

Diamondback has also entered into the following agreements with Rattler:

Rattler's Partnership Agreement

In connection with the closing of the Rattler Offering, Rattler's General Partner and Energen Resources entered into the first amended and restated agreement of limited partnership of Rattler, dated May 28, 2019 (the "Rattler Partnership Agreement"). The Rattler Partnership Agreement requires Rattler to reimburse Rattler's General Partner for all direct and indirect expenses incurred or paid on Rattler's behalf and all other expenses allocable to Rattler or otherwise incurred by Rattler's General Partner in connection with operating Rattler's business. The Rattler Partnership Agreement does not set a limit on the amount of expenses for which its 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 Rattler or on its behalf and expenses allocated to Rattler's General Partner by its affiliates. Rattler's General Partner is entitled to determine the expenses that are allocable to Rattler. For the year ended December 31, 2019, Rattler's General Partner allocated $364,342 of such expenses to Rattler.

Rattler's Services and Secondment Agreement

In connection with the closing of the Rattler Offering, Rattler entered into a services and secondment agreement with Diamondback, Diamondback E&P LLC, Rattler's General Partner and Rattler LLC, dated as of May 28, 2019 (the "Services and Secondment Agreement"). Pursuant to the Services and Secondment Agreement, Diamondback and its subsidiaries second certain operational, construction, design and management employees and contractors of Diamondback to Rattler's General Partner, Rattler and its subsidiaries, providing management, maintenance and operational functions with respect to Rattler's assets. The Services and Secondment Agreement requires Rattler's General Partner and Rattler to reimburse Diamondback for the cost of the seconded employees and contractors, including their wages and benefits. For the year ended December 31, 2019, Rattler's General Partner and Rattler paid Diamondback $5 million under the Services and Secondment Agreement.

Rattler's Tax Sharing Agreement

In connection with the closing of the Rattler Offering, Rattler LLC entered into a tax sharing agreement with Diamondback pursuant to which Rattler LLC will reimburse Diamondback for its share of state and local income and other taxes borne by Diamondback as a result of Rattler LLC's results being included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on May 28, 2019. The amount of any such reimbursement is limited to the tax that Rattler LLC would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which Rattler LLC may be a member for this purpose, to owe less or no tax. In such a situation, Rattler LLC agreed to reimburse Diamondback for the tax Rattler LLC would have owed had the attributes not been available or used for Rattler LLC's benefit, even though Diamondback had no cash expense for that period.

For the year ended December 31, 2019, Rattler accrued state income tax expense of $188,808 for its share of Texas margin tax for which Rattler's share of Rattler LLC's results are included in a combined tax return filed by Diamondback.

Rattler LLC's Revolving Credit Facility

Rattler LLC has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, sole book runner and lead arranger. See Note 10—Debt for a description of this credit facility.

6. REAL ESTATE ASSETS

In conjunction with Diamondback's acquisition of Fasken Towers Tall Towers, the Company allocated the $110 million purchase price between real estate assets and intangible lease assets related to in-place and above-market leases. In addition, the Company owns $10 million in office buildings. 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	December 31, 2019	December 31, 2018
	(Years)	(in millions)	
Buildings	20-30	$ 102	$ 103
Tenant improvements	15	5	4
Land	N/A	2	1
Land improvements	15	1	1
Total real estate assets		110	109
Less: accumulated depreciation		(9)	(4)
Total investment in land and buildings, net		$ 101	$ 105

	Weighted Average Useful Lives	December 31, 2019	December 31, 2018
	(Months)	(in millions)	
In-place lease intangibles	45	$ 11	$ 11
Less: accumulated amortization		(6)	(3)
In-place lease intangibles, net		5	8
Above-market lease intangibles	45	4	4
Less: accumulated amortization		(1)	(1)
Above-market lease intangibles, net		3	3
Total intangible lease assets, net		$ 8	$ 11

7. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31,	
	2019	2018
	(in millions)	
Oil and natural gas properties:		
Subject to depletion	$ 16,575	$ 12,629
Not subject to depletion	9,207	9,670
Gross oil and natural gas properties	25,782	22,299
Accumulated depletion	(2,995)	(1,599)
Accumulated impairment	(1,934)	(1,144)
Oil and natural gas properties, net	20,853	19,556
Midstream assets	931	700
Other property, equipment and land	125	147
Accumulated depreciation	(74)	(31)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 21,835	$ 20,372

Balance of costs not subject to depletion:	
Incurred in 2019	$ 604
Incurred in 2018	5,654
Incurred in 2017	2,329
Incurred in 2016	620
Total not subject to depletion	$ 9,207

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 $49 million, $29 million and $22 million for the years ended December 31, 2019, 2018 and 2017, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years. Acquisition costs not currently being amortized are primarily related to unproved acreage that the Company plans to prove up through drilling. The Company has no plans to let any acreage expire. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

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

As a result of the decline in commodity prices during 2019, the Company recorded a non-cash ceiling test impairment for the year ended December 31, 2019 of $790 million which was included in accumulated depletion. The impairment charge affected the Company's reported net income but did not reduce its cash flow. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2018.

At December 31, 2019, there was $228 million in exploration costs and development costs and $118 million in capitalized interest that are not subject to depletion. At December 31, 2018, there were $68 million exploration costs and development costs and $55 million capitalized interest that are not subject to depletion.

8. 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,		
	2019	2018	2017
	(in millions)		
Asset retirement obligations, beginning of period	$ 136	$ 21	$ 17
Additional liabilities incurred	8	3	2
Liabilities acquired	4	111	2
Liabilities settled	(61)	(2)	(1)
Accretion expense	7	2	1
Revisions in estimated liabilities	—	1	—
Asset retirement obligations, end of period	94	136	21
Less current portion	—	—	1
Asset retirement obligations - long-term	$ 94	$ 136	$ 20

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.

9. EQUITY METHOD INVESTMENTS

At December 31, 2019 and 2018, Rattler had the following investments:

	Net Ownership Interest	December 31, 2019	December 31, 2018
		(In millions)	
EPIC Crude Holdings, LP	10%	$ 110	$ —
Gray Oak Pipeline, LLC	10%	115	1
Wink to Webster Pipeline LLC	4%	34	—
OMOG JV LLC	60%	219	—
Amarillo Rattler, LLC	50%	1	—
		$ 479	$ 1

The following summarizes the income (loss) of equity method investees for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
EPIC Crude Holdings, LP	$ (6)	$ —	$ —
Gray Oak Pipeline, LLC	1	—	—
Wink to Webster Pipeline LLC	(1)	—	—
OMOG JV LLC	—	—	—
HMW LLC	—	—	1
	$ (6)	$ —	$ 1

In October 2014, the Company acquired a 25% interest in HMW Fluid Management LLC (“HMW 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.

On June 30, 2018, HMW LLC’s operating agreement was amended. As a result of the amendment, Rattler no longer recognizes an equity investment in HMW LLC but instead consolidates its undivided interest in the produced water disposal (“PWD”) assets owned by HMW LLC. In exchange for Rattler’s 25% investment, Rattler received a 50% undivided ownership interest in two of the four PWD wells and associated assets previously owned by HMW LLC. Rattler’s basis in the assets is equivalent to its basis in the equity investment in HMW LLC.

On February 1, 2019, Rattler LLC acquired a 10% equity interest in EPIC Crude Holdings, LP (“EPIC”), which is building a pipeline (the “EPIC project”) that, once fully operational, will transport crude and NGL across Texas for delivery into the Corpus Christi market. The EPIC project began initial operations during the third quarter of 2019.

On February 15, 2019, Rattler LLC acquired a 10% equity interest in Gray Oak Pipeline, LLC (“Gray Oak”), which is building a pipeline (the “Gray Oak project”) that, once operational, will transport crude from the Permian to Corpus Christi on the Texas Gulf Coast. The Gray Oak project began initial operations during the fourth quarter of 2019.

On March 29, 2019, Rattler LLC executed a short-term promissory note to Gray Oak. The note allows for borrowing by Gray Oak of up to $123 million at 2.52% interest rate with a maturity date of March 31, 2022. During the year ended December 31, 2019, there were $23 million in borrowings and repayments under this note. The short-term promissory note was repaid on May 31, 2019.

On June 4, 2019, Rattler entered into an equity contribution agreement with respect to Gray Oak. The equity contribution agreement requires Rattler to contribute equity or make loans to Gray Oak so that Gray Oak can, to the extent necessary, cure payment defaults under Gray Oak’s credit agreement and, in certain instances, repay Gray Oak’s credit agreement in full. Rattler’s obligations under the equity contribution agreement are limited to its proportionate ownership interest in Gray Oak, and such obligations are guaranteed by Rattler LLC, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC.

On July 30, 2019, Rattler LLC joined Wink to Webster Pipeline LLC as a 4% member, together with affiliates of ExxonMobil, Plains All American Pipeline, Delek US, MPLX LP and Lotus Midstream. The joint venture is developing a crude oil pipeline with origin points at Wink and Midland in the Permian Basin for delivery to multiple Houston area locations (the “Wink to Webster project”). The Wink to Webster project is expected to begin service in the first half of 2021.

On October 1, 2019, Rattler LLC acquired a 60% equity interest in OMOG JV LLC (“OMOG”). On November 7, 2019, OMOG acquired 100% of Reliance Gathering, LLC which operates a crude oil gathering system in the Permian, and was renamed as Oryx Midland Oil Gathering LLC following the acquisition. While Rattler’s equity interest is 60%, the investment is accounted for as an equity method investment as Rattler does not control operating activities and substantive participating rights exist with the controlling minority investor.

On December 20, 2019, Rattler LLC acquired a 50% equity interest in Amarillo Rattler LLC, which currently owns and operates the Yellow Rose gas gathering and processing system with estimated total processing capacity of 40,000 Mcf/d and over 84 miles of gathering and regional transportation pipelines in Dawson, Martin and Andrews Counties, Texas. This joint venture also intends to construct and operate a new 60,000 Mcf/d cryogenic natural gas processing plant in Martin County, Texas. While Rattler's equity interest is 50%, the investment is accounted for as an equity method investment as Rattler does not control operating activities and substantive participating rights exist with the controlling investor.

No impairments were recorded for Rattler's equity method investments for the year ended December 31, 2019 or 2018.

At December 31, 2019, there was $1 million of capitalized interest that was related to equity method investments that have not yet begun operations.

10. DEBT

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

	December 31,	
	2019	2018
	(in millions)	
4.625% Notes due 2021	$ 399	$ 400
7.320% Medium-term Notes, Series A, due 2022	21	20
2.875% Senior Notes due 2024	1,000	—
4.750% Senior Notes due 2024	—	1,250
5.375% Senior Notes due 2025	800	800
3.250% Senior Notes due 2026	800	—
7.350% Medium-term Notes, Series A, due 2027	11	10
7.125% Medium-term Notes, Series B, due 2028	108	100
3.500% Senior Notes due 2029	1,200	—
DrillCo Agreement	39	—
Unamortized debt issuance costs	(19)	(27)
Unamortized discount costs	(31)	—
Unamortized premium costs	9	10
Revolving credit facility	13	1,490
Viper revolving credit facility	97	411
Viper 5.375% Senior Notes due 2027	500	—
Rattler revolving credit facility	424	—
Total long-term debt	$ 5,371	$ 4,464

Diamondback Notes

4.750% Senior Notes

On October 28, 2016, the Company issued $500 million in aggregate principal amount of 4.750% senior notes due 2024 ("4.750% senior notes"), under an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On September 25, 2018, the Company issued $750 million aggregate principal amount of new 4.750% senior notes as additional notes under, and subject to the terms of, the same indenture governing the 4.750% senior notes. The Company received approximately $741 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 4.750% senior notes. The Company used a portion of the net proceeds from the issuance of the new 4.750% senior notes to repay a portion of the outstanding borrowings its revolving credit facility and the balance for general corporate purposes, including funding a portion of the cash consideration for the acquisition of certain assets from Ajax Resources, LLC..

On December 20, 2019, the Company redeemed all of the outstanding 4.750% senior notes. The redemption payment (the "Redemption Payment") included $1.25 billion of outstanding principal at a redemption price of 103.563% of the principal amount of the 4.750% senior notes, plus accrued and unpaid interest on the outstanding principal amount to the Redemption

Date. On December 5, 2019, the indenture governing the 4.750% senior notes was fully satisfied and discharged and the guarantors were released from their guarantees of the 4.750% senior notes. The Company funded the Redemption Payment with a portion of the net proceeds from the issuance of the December 2019 Notes.

The 4.750% senior notes bore 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 would have matured on November 1, 2024. All of our restricted subsidiaries that guaranteed our revolving credit facility guaranteed the 4.750% senior notes; provided, however, that the 4.750% senior notes were not guaranteed by Viper, Viper's General Partner, Viper LLC, Rattler, Rattler's General Partner or Rattler LLC.

2025 Senior Notes

On December 20, 2016, the Company issued $500 million in aggregate principal amount of 5.375% senior notes due 2025 (the "existing 2025 notes"), under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee (the "2025 indenture"). On January 29, 2018, the Company issued $300 million aggregate principal amount of new 5.375% senior notes due 2025 as additional notes under the 2025 indenture (the "new 2025 notes" and, together with the existing 2025 notes, the 2025 senior notes). The Company received approximately $308 million in net proceeds, after deducting the initial purchaser's discount and the Company's 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 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 the Company's existing and future restricted subsidiaries that guarantee its revolving credit facility guarantee the 2025 senior notes. Currently, the 2025 senior notes are not guaranteed by any of the Company's subsidiaries other than Diamondback O&G LLC and will not be guaranteed by any of the Company's future 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.

December 2019 Notes Offering

On December 5, 2019, the Company issued $1.0 billion in aggregate principal amount of 2.875% senior notes due 2024 (the "2024 notes"), $800 million in aggregate principal amount of 3.250% senior notes due 2026 (the "2026 notes"), and $1.2 billion aggregate principal amount of 3.500% senior notes due 2029, (the "2029 notes" and, together with the 2024 notes and the 2026 notes, the "December 2019 Notes"). The 2024 notes will mature on December 1, 2024, the 2026 notes will mature on December 1, 2026 and the 2029 notes will mature on December 1, 2029. Interest will accrue and be payable semi-annually, in arrears on June 1 and December 1 of each year, commencing on June 1, 2020. The December 2019 Notes are fully and unconditionally guaranteed by Diamondback O&G LLC and are not guaranteed by any of the Company's other subsidiaries.

The December 2019 Notes were issued under an indenture, dated as of December 5, 2019, among the Company and Wells Fargo, as the trustee, as supplemented by the first supplemental indenture dated as of December 5, 2019 (the "December 2019 Notes Indenture").

The Company may redeem (i) the 2024 Notes in whole or in part at any time prior to November 1, 2024 (one month prior to the maturity date of the 2024 Notes), (ii) the 2026 Notes in whole or in part at any time prior to October 1, 2026 (two months prior to the maturity date of the 2026 Notes) and (iii) the 2029 Notes in whole or in part at any time prior to September 1, 2029 (three months prior to the maturity date of the 2029 Notes) (each such date, a "par call date"), in each case at the redemption price set forth in the indenture governing the December 2019 Notes. If the December 2019 Notes are redeemed on or after their respective par call dates, in each case, such December 2019 Notes will be redeemed at a redemption price equal to 100% of the principal amount of the December 2019 Notes to be redeemed plus interest accrued thereon to but not including the redemption date.

Upon the occurrence of a Change of Control Triggering Event (as defined in the indenture governing the December 2019 Notes), holders may require the Company to purchase some or all of their December 2019 Notes for cash at a price equal to 101% of the principal amount of the December 2019 Notes being purchased, plus accrued and unpaid interest, if any, to the date of purchase.

The indenture governing the December 2019 Notes contains customary terms and covenants, including limitations on the Company's ability and the ability of certain of its subsidiaries to incur liens securing funded indebtedness and on the Company's ability to consolidate, merge or sell, convey, transfer or lease all or substantially all of its assets.

Second Amended and Restated Credit Facility

The Company and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, as amended, 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. On June 28, 2019, the credit agreement was amended pursuant to an eleventh amendment, which implemented certain changes to the credit facility for the period on and after the date on which our unsecured debt achieves an investment grade rating from two rating agencies and certain other conditions in the credit agreement are satisfied (the "investment grade changeover date"). On November 20, 2019, Diamondback O&G LLC caused Diamondback O&G LLC to deliver a notice as borrower under the revolving credit facility to trigger the "investment grade changeover date." As of December 31, 2019, the maximum credit amount available under the credit agreement is $2.0 billion. As of December 31, 2019, the Company had approximately $13 million of outstanding borrowings under its revolving credit facility and $1.99 billion available for future borrowings under the revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement, and, as of December 31, 2019, the credit agreement is guaranteed by Diamondback Energy, Inc. None of the Company's other subsidiaries are guarantors under the revolving credit facility. On December 5, 2019, Diamondback O&G LLC delivered a letter notifying the administrative agent under the credit agreement that as of such date, each of the guarantors, other than Diamondback Energy, Inc., ceased to be a guarantor under the credit agreement.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to the 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 with range from 0.125% to 1.0% per annum and from 1.125% to 2.0% per annum in the case of LIBOR, in each case, depending on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt. We are obligated to pay a quarterly commitment fee ranging from 0.125% to 0.350% per year on the unused portion of the commitment, based on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt.

Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage). Loan principal is required to be repaid (a) to the extent the loan amount exceeds the commitment due to any termination or reduction of the aggregate maximum credit amount and (b) at the maturity date of November 1, 2022.

The credit agreement contains a financial covenant that requires us to maintain a Total Net Debt to Capitalization Ratio (as defined in the credit agreement) of no more than 65%. Our non-guarantor restricted subsidiaries may incur debt for borrowed money in an aggregate principal amount up to 15% of consolidated net tangible assets (as defined in the credit agreement) and we and our restricted subsidiaries may incur liens if the aggregate amount of debt secured by such liens does not exceed 15% of consolidated net tangible assets.

As of December 31, 2019 and 2018, the Company was in compliance with all financial covenants under the revolving credit facility, as then in effect. 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.

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 million in notes (the "Energen Notes"), issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee (the "Energen Indenture"). As of December 31, 2019, the Energen Notes consist of: (1) $399 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (2) $108 million of 7.125% notes due on February 15, 2028, (3) $21 million of 7.32% notes due on July 28, 2022, and (4) $11 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, 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 if any, and are effectively subordinated to Energen's senior secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness. Neither we nor any of our subsidiaries guarantee the Energen Notes.

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 and the 2025 Indenture, Energen is also a guarantor of the 2025 Senior Notes.

Viper's Facility - Wells Fargo Bank

On July 20, 2018, Viper LLC, as borrower, entered into an amended and restated credit agreement with Viper, as guarantor, Wells Fargo, as administrative agent, and the other lenders. The credit agreement, as amended (the "Viper credit agreement"), provides for a revolving credit facility in the maximum credit amount of $2 billion and a borrowing base based on Viper LLC's oil and natural gas reserves and other factors (the "borrowing base") of $775 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, Viper LLC and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. In connection with Viper's fall redetermination in November 2019, the borrowing base under the Viper credit agreement was increased to $775 million. As of December 31, 2019, the borrowing base was set at $775 million, and Viper LLC had $97 million of outstanding borrowings and $678 million available for future borrowings under the Viper credit agreement.

The outstanding borrowings under the Viper credit agreement bear interest at a per annum rate elected by Viper LLC that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. Viper LLC 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 Viper and Viper LLC.

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, purchases of margin stock 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 Viper credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined the Viper 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 $1.0 billion 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. The covenant limiting dividends and distributions includes an exception allowing Viper LLC to make distributions if no default, event of default or borrowing base deficiency exists.

As of December 31, 2019 and 2018, Viper and Viper LLC were in compliance with all financial covenants under the Viper credit agreement, as then in effect. The lenders may accelerate all of the indebtedness under the Viper credit agreement upon the occurrence and during the continuance of any event of default. The Viper credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control.

Viper's Notes

On October 16, 2019, Viper completed an offering in which it issued its 5.375% Senior Notes due 2027 in aggregate principal amount of $500 million (the "Viper Notes"). Viper received gross proceeds of $500 million from the such offering, which it loaned to Viper LLC. Viper LLC paid the expenses of the offering, resulting in net proceeds of the offering of $490 million, which Viper LLC used to pay down borrowings under the Viper credit agreement.

The Viper Notes were issued under an indenture, dated as of October 16, 2019, among Viper, as issuer, Viper LLC, as guarantor and Wells Fargo, as trustee (the "Viper Indenture"). Pursuant to the Viper Indenture and the Viper Notes, interest on the Viper Notes accrues at a rate of 5.375% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2020. The Viper Notes will mature on November 1, 2027.

Viper LLC guarantees the Viper Notes pursuant to the Viper Indenture. Neither the Company nor any of its other subsidiaries guarantee the Viper Notes.

The Viper Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit Viper's ability and the ability of its restricted subsidiaries to incur or guarantee additional indebtedness or issue certain redeemable or preferred equity, make certain investments, declare or pay dividends or make distributions on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness, transfer or sell assets, agree to payment restrictions affecting its restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens and designate certain of its subsidiaries as unrestricted subsidiaries. These covenants are subject to numerous exceptions, some of which are material. Certain of these covenants are subject to termination upon the occurrence of certain events.

Rattler's Credit Agreement

In connection with the Rattler Offering, Rattler, as parent, and Rattler LLC, as borrower, entered into a credit agreement, dated May 28, 2019, with Wells Fargo Bank, as administrative agent, and a syndicate of banks, as lenders party thereto (the "Rattler credit agreement").

The Rattler credit agreement provides for a revolving credit facility in the maximum credit amount of $600 million. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid at the maturity date of May 28, 2024. The Rattler credit agreement is guaranteed by Rattler, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC. As of December 31, 2019, Rattler LLC had $424 million of outstanding borrowings and $176 million available for future borrowings under the Rattler credit agreement.

The outstanding borrowings under the Rattler credit agreement bear interest at a per annum rate elected by Rattler LLC that is based on the prime rate or LIBOR, in each case plus an applicable margin. The applicable margin ranges from 0.250% to 1.250% per annum for prime-based loans and 1.250% to 2.250% per annum for LIBOR loans, in each case depending on the Consolidated Total Leverage Ratio (as defined in the Rattler credit agreement). Rattler LLC is obligated to pay a quarterly commitment fee ranging from 0.250% to 0.375% per annum on the unused portion of the commitment, which fee is also dependent on the Consolidated Total Leverage Ratio.

The Rattler credit agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, distributions and other restricted payments, transactions with affiliates, and entering into certain swap agreements, in each case of Rattler, Rattler LLC and their restricted subsidiaries. The covenants are subject to exceptions set forth in the Rattler credit agreement, including an exception allowing Rattler LLC or Rattler to issue unsecured debt securities and an exception allowing payment of distributions if no default exists.

The Rattler credit agreement also contains financial maintenance covenants that require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Consolidated Total Leverage Ratio commencing with the fiscal quarter ending September 30, 2019	Not greater than 5.00 to 1.00 (or not greater than 5.50 to 1.00 for 3 fiscal quarters following certain acquisitions), but if the Consolidated Senior Secured Leverage Ratio (as defined in the Rattler credit agreement) is applicable, then not greater than 5.25 to 1.00)
Consolidated Senior Secured Leverage Ratio commencing with the last day of any fiscal quarter in which the Financial Covenant Election (as defined in the Rattler credit agreement) is made	Not greater than 3.50 to 1.00
Consolidated Interest Coverage Ratio (as defined in the Rattler credit agreement) commencing with the fiscal quarter ending September 30, 2019	Not less than 2.50 to 1.00

For purposes of calculating the financial maintenance covenants prior to the fiscal quarter ending June 30, 2020, EBITDA (as defined in the Rattler credit agreement) will be annualized based on the actual EBITDA for the preceding fiscal quarters starting with the fiscal quarter ending September 30, 2019.

As of December 31, 2019, Rattler and Rattler LLC were in compliance with all financial covenants under the Rattler credit agreement. The lenders may accelerate all of the indebtedness under the Rattler credit agreement upon the occurrence and during the continuance of any event of default. The Rattler credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change in control.

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 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, 2019, CEMOF had funded approximately $36 million. As of December 31, 2019, eleven joint wells have been drilled and completed.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
	(in millions)		
Interest expense	$ 235	$ 110	$ 61
Less capitalized interest	(66)	(32)	(22)
Other fees and expenses	4	10	2
Total interest expense	$ 173	$ 88	$ 41

11. CAPITAL STOCK AND EARNINGS PER SHARE

The Company did not complete any equity offerings during the years ended December 31, 2019, 2018 and 2017.

Viper Equity Offerings

For information regarding Viper's completed equity offerings during the years ended December 31, 2019, 2018 and 2017, refer to Note 4—Viper Energy Partners LP.

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 Viper are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiary.

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

	Year Ended December 31,		
	2019	2018	2017
	(In millions, except per share amounts, shares in thousands)		
Net income attributable to common stock	$ 240	$ 846	$ 482
Weighted average common shares outstanding:			
Basic weighted average common units outstanding	163,493	104,622	97,458
Effect of dilutive securities:			
Potential common shares issuable	350	307	230
Diluted weighted average common shares outstanding	163,843	104,929	97,688
Basic net income attributable to common stock	$ 1.47	$ 8.09	$ 4.95
Diluted net income attributable to common stock	$ 1.47	$ 8.06	$ 4.94

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,		
	2019	2018	2017
	(in thousands)		
Restricted stock units	284	14	46

12. 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 1,313,588 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,		
	2019	2018	2017
	(In millions)		
General and administrative expenses	$ 48	$ 27	$ 25
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 17	$ 10	$ 9

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, 2019:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	324,224	$ 116.01
Granted	697,679	$ 99.36
Vested	(425,608)	$ 105.09
Forfeited	(90,428)	$ 106.55
Unvested at December 31, 2019	505,867	$ 96.01

The aggregate fair value of restricted stock units that vested during the years ended December 31, 2019, 2018 and 2017 was $45 million, $19 million and $15 million, respectively. As of December 31, 2019, the Company’s unrecognized compensation cost related to unvested restricted stock awards and units was $38 million. Such cost is expected to be recognized over a weighted-average period of 2.2 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 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 vested 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.

In March 2019, eligible employees received performance restricted stock unit awards totaling 199,723 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, 2019 to December 31, 2021 and cliff vest at December 31, 2021. In March 2019, eligible employees received performance restricted stock unit awards totaling 32,958 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, 2019 to December 31, 2021 and vest in five equal installments beginning on March 1, 2025.

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

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

	2019	2018	2017	
	Three-Year Performance Period	Three-Year Performance Period	Two-Year Performance Period	Three-Year Performance Period
Grant-date fair value	$ 137.22	$ 170.45	$ 162.13	$ 168.73
Grant-date fair value (5-year vesting)	$ 132.48			
Risk-free rate	2.55%	1.99%	1.27%	1.59%
Company volatility	35.00%	35.90%	39.32%	41.14%

The following table presents the Company’s performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2019:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	196,203	$ 169.76
Granted	356,227	$ 131.30
Vested	(176,976)	$ 93.32
Forfeited	(103,635)	$ 155.23
Unvested at December 31, 2019(1)	271,819	$ 147.07

(1) A maximum of 543,638 units could be awarded based upon the Company’s final TSR ranking.

As of December 31, 2019, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $24 million. Such cost is expected to be recognized over a weighted-average period of 2.6 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.

The following table presents a summary of stock appreciation rights activity during the year ended December 31, 2019:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2018	57,721	$ 22.12
Exercised	(11,399)	$ 70.69
Expired	(3,775)	$ 96.91
Outstanding at December 31, 2019	42,547	$ 90.89

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 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.

		Weighted Average		
	Options	Exercise Price	Remaining Term	Intrinsic Value
			(in years)	(in millions)
Outstanding at December 31, 2018	332,387	$ 95.04		
Exercised	(116,044)	$ 82.29		
Outstanding at December 31, 2019	216,343	$ 89.90	1.67	$ —
Vested and Expected to vest at December 31, 2019	216,343	$ 89.90	1.67	$ —
Exercisable at December 31, 2019	216,343	$ 89.90	1.67	$ —

Viper Long-Term Incentive Plan

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 Viper. 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 8,892,918 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.

Under the Viper LTIP, the Board of Directors of Viper's General Partner is authorized to issue phantom units to eligible employees. Viper estimates the fair value of phantom units as the closing price of Viper'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 Viper for each phantom unit.

The following table presents the phantom unit activity under the Viper LTIP for the year ended December 31, 2019:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	125,053	$ 23.44
Granted	56,582	$ 30.33
Vested	(85,359)	$ 23.96
Forfeited	(1,028)	$ 42.50
Unvested at December 31, 2019	95,248	$ 26.87

The aggregate fair value of phantom units that vested during the year ended December 31, 2019 was $2 million. As of December 31, 2019, the unrecognized compensation cost related to unvested phantom units was $1 million. Such cost is expected to be recognized over a weighted-average period of 1.0 years.

Rattler Long-Term Incentive Plan

On May 22, 2019, the board of directors of Rattler's General Partner adopted the Rattler Midstream LP Long Term Incentive Plan ("Rattler LTIP"), for employees, consultants and directors of Rattler's General Partner and any of its affiliates, including Diamondback, who perform services for Rattler. The Rattler 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.

Under the Rattler LTIP, the board of directors of Rattler's General Partner is authorized to issue phantom units to eligible employees and non-employee directors. Rattler estimates the fair value of phantom units as the closing price of Rattler'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 to one common unit of Rattler for each phantom unit. The recipients are also entitled to distribution equivalent rights, which represent the right to receive a cash payment equal to the value of the distributions paid on one phantom unit between the grant date and the vesting date.

The following table presents the phantom unit activity under the Rattler LTIP for the year ended December 31, 2019:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at May 28, 2019	—	$ —
Granted	2,284,038	$ 19.14
Forfeited	(57,143)	$ 19.21
Unvested at December 31, 2019	2,226,895	$ 19.14

As of December 31, 2019, the unrecognized compensation cost related to unvested phantom units was $37 million. Such cost is expected to be recognized over a weighted-average period of 2.4 years.

13. RELATED PARTY TRANSACTIONS

Advisory Services Agreement - Viper

In connection with the closing of the Viper Offering, Viper and Viper's General Partner entered into an advisory services agreement (the "Viper Advisory Services Agreement") with Wexford, dated as of June 23, 2014, under which Wexford provided Viper and Viper's General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement was terminated on November 12, 2018 and Viper's payment obligation ended in June 2019. During 2019, Viper did not pay any amounts under the Advisory Services Agreement. For the year ended December 31, 2018, Viper did not pay any amounts under the Advisory Services Agreement.

Lease Bonus - Viper

During the year ended December 31, 2019, the Company paid Viper $277,977 in lease bonus payments to extend the term of six leases and $182,646 in lease bonus payments for four new leases. During the year ended December 31, 2018, the Company paid Viper $3 million in lease bonus payments to extend the term of 13 leases and less than $1 million in lease bonus payments for one new lease. During the year ended December 31, 2017, the Company paid Viper $105,690 in lease bonus payments to extend the term of two leases.

Please see Note 4—Viper Energy Partners LP for additional information regarding relationships between the Company and Viper.

Rattler Offering

Please see Note 5—Rattler Midstream LP for information regarding relationships between the Company and Rattler.

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 Viper, Viper LLC, Rattler and Rattler LLC, file a federal corporate income tax return on a consolidated basis. As discussed further below, Viper 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 Viper LLC. Subsequent to Rattler's election to be treated as a corporation for federal income tax purposes effective May 24, 2019, Rattler is also a taxable entity and as such files a federal corporate income tax return including the activity of its investment in Rattler LLC. Viper's and Rattler'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. 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 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 $68 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 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 did not made any adjustments to the provisional amounts recorded December 31, 2017.

The Company's effective income tax rates were 13.0% and 15.1% for the years ended December 31, 2019 and 2018, respectively. Total income tax expense for the year ended December 31, 2019 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income for the period primarily due to the revision of estimated deferred taxes recognized as a result of Viper's change in tax status, and state income taxes net of federal benefit. Total income tax expense for the year ended December 31, 2018 differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to the impact of deferred taxes recognized as a result of Viper's change in tax status, net income attributable to the noncontrolling interest, and state income taxes net of federal benefit.

The components of the Company’s consolidated provision for income taxes from continuing operations for the years ended December 31, 2019, 2018 and 2017 are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Current income tax provision (benefit):			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax provision (benefit)	—	—	—
Deferred income tax provision (benefit):			
Federal	40	160	(21)
State	7	8	1
Total deferred income tax provision (benefit)	47	168	(20)
Total provision for (benefit from) income taxes	$ 47	$ 168	$ (20)

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

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Income tax expense at the federal statutory rate(1)	$ 76	$ 234	$ 174
Impact of nontaxable noncontrolling interest	—	(5)	(12)
Income tax benefit relating to change in statutory tax rate	—	—	(68)
State income tax expense, net of federal tax effect	6	8	3
Non-deductible compensation	4	5	13
Change in valuation allowance	—	—	(127)
Deferred taxes related to change in Viper LP's tax status	(42)	(73)	—
Other, net	3	(1)	(3)
Provision for (benefit from) income taxes	$ 47	$ 168	$ (20)

(1) The federal statutory rates for the years ended December 31, 2019, 2018 and 2017 were 21%, 21% and 35%, respectively.

The components of the Company's deferred tax assets and liabilities as of December 31, 2019 and 2018 are as follows:

	December 31,	
	2019	2018
	(In millions)	
Deferred tax assets:		
Net operating loss and other carryforwards	$ 453	$ 155
Stock based compensation	7	7
Viper LP's investment in Viper LLC	134	94
Other	11	9
Deferred tax assets	605	265
Valuation allowance	(7)	(14)
Deferred tax assets, net of valuation allowance	598	251
Deferred tax liabilities:		
Oil and natural gas properties and equipment	2,275	1,825
Midstream investments	50	67
Derivative instruments	6	47
Rattler LP's investment in Rattler LLC	8	—
Other	3	—
Total deferred tax liabilities	2,342	1,939
Net deferred tax liabilities	$ 1,744	$ 1,688

The Company had net deferred tax liabilities of approximately $1.7 billion at December 31, 2019 and 2018. 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 $1.4 billion associated with the acquired assets, which includes deferred tax assets related to tax attributes acquired from Energen. As of December 31, 2019, the Company has completed its purchase price allocation for the acquisition, including an increase of $23 million to the deferred tax liability as a result of adjustments to fair value of the acquired assets.

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 as a result of its loss, nor is there any current federal income tax payable. At December 31, 2019, the Company had approximately $400 million of federal NOLs expiring in 2032 through 2037 and $1.3 billion 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's federal tax attributes acquired from Energen are subject to an annual limitation under 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. The Company believes that the application of Section 382 will not have an adverse effect on future usage of the Company's NOLs and credits, including federal tax attributes acquired from Energen. The Company's minimum tax credits, including those acquired from Energen, are classified as $19 million current and $19 million noncurrent income tax receivables on the balance sheet.

As of December 31, 2019, the Company has a valuation allowance of $7 million primarily related to certain state NOL carryforwards 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 of December 31, 2019, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

As discussed further in Note 4—Viper Energy Partners LP, on March 29, 2018, Viper announced that the Board of Directors of its General Partner had unanimously approved a change of Viper's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. The transactions undertaken in connection with the change in Viper's tax status were not taxable to the Company. Subsequent to Viper's change in tax status, Viper's provision for income taxes for the periods ended December 31, 2018 and 2019 are based on its estimated annual effective tax rate plus discrete items. As such, Viper'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, 2019, the Company's net deferred tax liabilities include a deferred tax asset of approximately $134 million related to Viper's investment in Viper LLC, approximately $115 million of which was recorded as a result of Viper's change in tax status. Under federal income tax provisions applicable to Viper's change in tax status, Viper's basis for federal income tax purposes in its interest in Viper LLC consisted primarily of the sum of Viper's unitholders' tax bases in their interests in Viper on the date of the tax status change. Viper prepared its best estimate of the tax basis in Viper LLC for purposes of Viper's income tax provision for the period of the change, but information necessary for Viper to finalize its determination was not available until unitholders' tax basis information was fully reported and Viper finalized its federal income tax computations for 2018. Based on such finalized information as of the third quarter 2019, Viper revised its estimate of the difference between its tax basis and its basis for financial accounting purposes in Viper LLC on the date of the tax status change, resulting in deferred income tax benefit of $42 million included in the Company's consolidated income tax provision for the year ended December 31, 2019. As of December 31, 2019, Viper has federal net operating loss carryforwards of approximately $38 million which may be carried forward indefinitely to offset future taxable income.

As discussed further in Note 5—Rattler Midstream LP, on May 28, 2019, Rattler completed its initial public offering. Even though Rattler is organized as a limited partnership under state law, Rattler is subject to U.S. federal and state income tax at corporate rates, subsequent to the effective date of Rattler's election to be treated as a corporation for U.S. federal income tax purposes. As such, Rattler'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, 2019, the Company's net deferred tax liabilities include a deferred tax liability of approximately $8 million related to Rattler's investment in Rattler LLC. Subsequent to the deemed formation of Rattler LLC as a partnership for federal income tax purposes upon Rattler's IPO, deferred taxes are no longer provided on the underlying assets and liabilities of Rattler LLC but are provided on the difference between Rattler's basis for financial accounting purposes and basis for federal income tax purposes in its investment in Rattler LLC. Rattler incurred an NOL in the current year due principally to Rattler LLC's tax deductions for accelerated depreciation, which exceeded its other items of taxable income. At December 31, 2019, Rattler has federal net operating loss carryforwards of approximately $1 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,	
	2019	2018
	(in millions)	
Balance at beginning of year	$ 7	$ —
Increase resulting from tax positions acquired	—	7
Increase resulting from prior period tax positions	—	—
Increase resulting from current period tax positions	—	—
Balance at end of year	7	7
Less: Effects of temporary items	(5)	(5)
Total that, if recognized, would impact the effective income tax rate as of the end of the year	$ 2	$ 2

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.

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, 2019 and 2018, there were no penalties and less than $1 million and $0 million of interest, respectively, associated with uncertain tax positions recognized in the Company's consolidated 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."

Commodity Contracts

The Company has used fixed price swap contracts, fixed price basis swap contracts, double-up swap contracts and three-way costless collars with corresponding put, short put and call options to reduce price volatility associated with certain of its oil and natural gas sales. With respect to the Company's fixed price swap contracts and fixed price basis swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap or basis price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap or basis price. The Company has fixed price basis swaps for the spread between the WTI 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. The Company also utilizes double-up swap contracts for a portion of its natural gas sales. These contracts include a traditional fixed price swap in addition to a call option at the same quantity and price, providing the counterparty the option to double the volume in the swap contract should the monthly settlement price exceed the fixed price contracted upon.

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 the New York Mercantile Exchange Henry Hub 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, 2019, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed:

	2020			2021		
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)		Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)	
Oil Swaps - WTI Cushing	4,754,000	$	57.78	0	$	—
Oil Swaps - WTI Magellan East Houston	2,196,000	$	62.80	0	$	—
Oil Swaps - BRENT	4,569,000	$	61.84	0	$	—
Oil Basis Swaps - WTI Cushing	13,860,000	$	(1.20)	0	$	—
Oil Rolling Hedge - WTI Cushing	6,700,000	$	0.44	0	$	—
Natural Gas Swaps - Henry Hub	10,050,000	$	2.55	0	$	—
Natural Gas Swaps - Waha Hub	16,750,000	$	1.67	0	$	—
Natural Gas Basis Swaps - Waha Hub	23,450,000	$	(1.19)	54,750,000	$	(0.70)

	2020					
Oil Three-Way Collars	WTI Cushing		Brent		WTI Magellan East Houston	
Volume (Bbls)		6,842,200		11,803,500		5,124,000
Short put price (per Bbl)	$	44.20	$	50.00	$	50.00
Floor price (per Bbl)	$	54.20	$	60.00	$	60.00
Ceiling price (per Bbl)	$	65.42	$	70.86	$	68.61

Gas Swap Double-Up - Waha Hub	2020	
Volume (Mcf)		10,050,000
Swap price (per Mcf)	$	1.70
Option price	$	1.70

Interest Rate Swaps and Treasury Locks

The Company has used interest rate swaps and treasury locks to reduce the Company’s exposure to variable rate interest payments associated with the Company’s revolving credit facility. The interest rate swaps and treasury locks have not been designated as hedging instruments and as a result, the Company recognizes all changes in fair value immediately in earnings. Effective November 2019, the Company terminated all of its interest rate swaps and treasury locks which resulted in a gain of $43 million, net of fees.

Balance sheet offsetting of derivative assets and liabilities

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

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of December 31, 2019 and 2018:

	December 31,	
	2019	2018
	(in millions)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$ 71	$ 233
Amounts netted in the Consolidated Balance Sheet	(18)	(2)
Net amounts of assets presented in the Consolidated Balance Sheet	$ 53	$ 231
Gross amounts of liabilities presented in the Consolidated Balance Sheet	$ 45	$ 15
Amounts netted in the Consolidated Balance Sheet	(18)	—
Net amounts of liabilities presented in the Consolidated Balance Sheet	$ 27	$ 15

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,	
	2019	2018
	(in millions)	
Current assets: derivative instruments	$ 46	$ 231
Noncurrent assets: derivative instruments	7	—
Total assets	$ 53	$ 231
Current liabilities: derivative instruments	$ 27	$ —
Noncurrent liabilities: derivative instruments	—	15
Total liabilities	$ 27	$ 15

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,		
	2019	2018	2017
	(in thousands)		
Change in fair value of open non-hedge derivative instruments:	$ (188)	$ 222	$ (84)
Gain (loss) on settlement of non-hedge derivative instruments:	80	(121)	6
Gain (loss) on derivative instruments	$ (108)	$ 101	$ (78)

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.

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 8—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 and Viper’s cost method investment. The fair value of Viper’s investment is determined using quoted market prices. These valuations are Level 1 inputs. 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, 2019 and 2018:

	December 31, 2019			December 31, 2018		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in millions)					
Assets:						
Investment	$ 19	$ —	$ —	$ 14	$ —	$ —
Fixed price swaps	$ —	$ 26	$ —	$ —	$ 216	$ —
Liabilities:						
Fixed price swaps	$ —	$ —	$ —	$ —	$ —	$ —

Table of Contents

The following table summarizes the changes in fair value of Viper's cost method investment during the periods presented:

	(in millions)	
Value at December 31, 2018	$	14
Gain on investment		5
Value at December 31, 2019	$	19
Value at December 31, 2017	$	34
Impact of adoption of Accounting Standards Update 2016-01		(19)
Loss on investment		(1)
Value at December 31, 2018	$	14

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, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 13	$ 13	$ 1,490	$ 1,490
4.625% Notes due 2021	399	411	400	393
7.320% Medium-term Notes, Series A, due 2022	21	22	20	21
2.875% Senior Notes due 2024[(1)]	992	1,012	—	—
4.750% Senior Notes due 2024[(1)]	—	—	1,236	1,204
5.375% Senior Notes due 2025[(1)]	799	840	799	782
3.250% Senior Notes due 2026[(1)]	792	812	—	—
7.350% Medium-term Notes, Series A, due 2027	11	12	10	11
7.125% Medium-term Notes, Series B, due 2028	108	116	100	102
3.500% Senior Notes due 2029[(1)]	1,186	1,226	—	—
Viper revolving credit facility	97	97	411	411
Viper's 5.375% Senior Notes due 2027	490	521	—	—
Rattler revolving credit facility	424	424	—	—
DrillCo Agreement	$ 39	$ 39	$ —	$ —

(1) The carrying value includes associated deferred loan costs and any discount.

The fair value of the revolving credit facility, the Viper credit agreement and the Rattler credit agreement 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, 2019 quoted market price, a Level 1 classification in the fair value hierarchy.

17. LEASES

The Company leases certain drilling rigs, facilities, compression and other equipment.

As discussed in Note 2—Summary of Significant Accounting Policies, the Company adopted ASU 2016-02, ASU 2018-11 and ASU 2019-01 on January 1, 2019 using the optional transition method of adoption. The Company elected a package of practical expedients that together allows an entity to not reassess (i) whether a contract is or contains a lease, (ii) lease classification and (iii) initial direct costs. In addition, the Company elected the following practical expedients: (i) to not reassess certain land easements; (ii) to not apply the recognition requirements under the standard to short-term leases; (iii) to not reassess lease terms on leases entered into prior to the effective date of adoption; and (iv) lessor accounting policy election to exclude lessor costs paid directly by the lessee.

For leases where the Company is the lessee, the Company recorded a total of $13 million in right-of-use assets and corresponding new lease liabilities in other on its Condensed Consolidated Balance Sheet representing the present value of its future operating lease payments. Adoption of the standards did not require an adjustment to the opening balance of retained earnings. The discount rate used to determine present value was based on the rate of interest that the Company estimated it would have to pay to borrow (on a collateralized-basis over a similar term) an amount equal to the lease payments in a similar economic environment as of January 1, 2019. The Company is required to reassess the discount rate for any new and modified lease contracts as of the lease effective date.

The right-of-use assets and lease liabilities recognized upon adoption of ASU 2016-02 were based on the lease classifications, lease commitment amounts and terms recognized under the prior lease accounting guidance. Leases with an initial term of twelve months or less are considered short-term leases and are not recorded on the balance sheet.

The following table summarizes operating lease costs for the year ended December 31, 2019:

	Year Ended December 31, 2019	
	(in millions)	
Operating lease costs	$	26

For the year ended December 31, 2019, cash paid for operating lease liabilities, and reported in cash flows provided by operating activities on the Company's Statement of Condensed Consolidated Cash Flows, was $26 million. During the year ended December 31, 2019, the Company recorded an additional $17 million of right-of-use assets in exchange for new lease liabilities.

The operating lease right-of-use assets were reported in other assets and the current and noncurrent portions of the operating lease liabilities were reported in other accrued liabilities and other long-term liabilities, respectively, on the Condensed Consolidated Balance Sheet. As of December 31, 2019, the operating right-of-use assets were $15 million and operating lease liabilities were $15 million, of which $8 million was classified as current. As of December 31, 2019, the weighted average remaining lease term was 2.1 years and the weighted average discount rate was 8.2%.

Schedule of Operating Lease Liability Maturities. The following table summarizes undiscounted cash flows owed by the Company to lessors pursuant to contractual agreements in effect as of December 31, 2019:

	As of December 31, 2019	
	(in millions)	
2020	$	9
2021		5
2022		2
2023		—
2024		—
Thereafter		—
Total lease payments		16
Less: interest		1
Present value of lease liabilities	$	15

For leases in which the Company is the lessor, the Company (i) retained classification of our historical leases as we are not required to reassess classification upon adoption of the new standard, (ii) expensed indirect leasing costs in connection with new or extended tenant leases, the recognition of which would have been deferred under prior accounting guidance and (iii) aggregated revenue from our lease components and non-lease components (comprised of tenant expense reimbursements) into revenue from rental properties.

18. COMMITMENTS AND CONTINGENCIES

The Company is a party to various legal proceedings, disputes and claims arising in the course of its business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and gas exploration and development and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer part of the Company’s current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on the Company, cannot be predicted with certainty, the Company believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Company’s financial condition, cash flows or results of operations. The Company’s assessment is based on information known about the pending matters and its experience in contesting, litigating and settling similar matters. Actual outcomes could differ materially from the Company’s assessment. The Company records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated. The Company reassesses the probability and estimability of contingent losses as new information becomes available.

Commitments

The following is a schedule of minimum future payments with commitments that have initial or remaining noncancelable terms in excess of one year as of December 31, 2019:

Year Ending December 31,	Sand Supply Agreement
	(in millions)
2020	$ 18
2021	18
2022	18
2023	18
2024	18
Thereafter	23
Total	$ 113

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.

The following table presents rent expense for the years ended December 31, 2019, 2018 and 2017:

	Year ended December 31,		
	2019	2018	2017
	(in millions)		
Rent Expense	$ 3	$ 1	$ 2

Agreement with Trafigura Trading LLC

The Company has entered into a firm commitment oil purchase agreement with Trafigura Trading LLC (“Trafigura”) in which the Company agreed to sell and deliver a firm quantity of 25,000 barrels of crude oil per day 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 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 Plains Marketing LP

In July 2019, the Company's wholly-owned subsidiary, Energen Resources Corporation ("Energen Resources") entered into a long-term crude oil sales agreement with Plains Marketing LP ("Plains") pursuant to which, among other things, the Company's existing agreements with Plains were terminated. The Company's new agreement with Plains requires that it makes available 50,000 barrels of crude oil per day until the date occurring ten years following the date service commences for ExxonMobil Oil Corporation ("Exxon") pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier (plus extensions for force majeure). 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 or acts or omissions of Plains, the Company has agreed to pay Plains a specified per barrel amount, subject to escalation, multiplied by the deficiency volume. If during the term of the agreement the Company fails to deliver the quantities of oil for any month that it has committed for such month other than for specified force majeure events or acts or omissions of Plains, the Company has agreed to pay Plains a deficiency payment . The Company has also dedicated certain crude oil production attributable to certain of its interests to Plains in connection with this agreement. Pricing for the Company's production under the Plains agreement (i) prior to the date service commences for Exxon pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier, is at a Midland WTI or WTL, as applicable, base price less certain costs and (ii) following the date service commences for Exxon pursuant to the transportation service agreement between Exxon and the Wink to Webster pipeline carrier, for volumes up to 100,000 barrels of crude oil per day, is at a MEH WTI or WTL base price, as applicable, less certain costs.

Agreement with Shell Trading (USA) Company

In December 2018, the Company entered into an oil purchase agreement with Shell Trading (USA) Company ("Shell") which was amended and restated in December 2019, in which Shell agreed to transport crude oil it purchases from us through the EPIC pipeline, with which the Company has an agreement for the transportation of certain crude oil. The Company's agreement with Shell provides for different purchase obligations during the pre-commencement and service commencement periods for the EPIC pipeline, and provides for a three-year term beginning on the service commencement date for the EPIC pipeline. Shell has the option to extend its purchase obligations for up to three one-year terms, but not beyond March 31, 2026 except in the event of force majeure. The Company's delivery obligation (i) prior to the full service commencement of the EPIC pipeline will be, subject to certain conditions, including the Company's right to repurchase certain volumes, either 30,000 or 40,000 barrels of crude oil per day and (ii) during the full service term will not exceed 50,000 barrels of crude oil per day. In addition, the Company's wholly-owned subsidiary Energen Resources has signed an agreement with Shell in which all or a portion of the 50,000 barrels of crude oil per day referenced in the previous sentence could also be satisfied by Energen Resources. During different pre-commencement periods, Shell has agreed to pay the Company the price per barrel of oil based on the arithmetic average of the daily settlement price for the "Light Sweet Crude Oil" Prompt Month future contracts reported by the NYMEX over the applicable one-month period, subject to certain adjustments, plus a Corpus Christi differential determined based on Shell's average sales price for its WTI barrels in Corpus Christi less certain other costs, expenses and fees. During the full service term, the price per barrel of oil payable by Shell to the Company is based on calendar dated Brent pricing plus a negotiated differential generally based on certain Argus WTI Houston CIF Rotterdam and Platts Midland DAP Rotterdam pricing, less certain adjustments.

Agreement with Vitol Inc.

On October 18, 2018, the Company entered into an agreement with Vitol to, among other things, sell an average of 23,750 barrels of crude oil per day plus other agreed upon volumes. The Company is continuing to sell crude to Vitol on a month-to-month basis and expects to continue to do so under its existing arrangement with Vitol until its new agreement with Vitol becomes effective. Under the Company's new agreement with Vitol, the Company agreed to sell, and Vitol agreed to purchase, (i) subject to certain conditions, including accelerated commissioning service on the Gray Oak pipeline and completion of certain infrastructure connections, 50,000 barrels of crude oil per day on average during each month occurring during the first seven years of full service on the Gray Oak pipeline, (ii) subject to certain conditions and the satisfaction of other conditions, including full service on the Gray Oak pipeline and completion of certain infrastructure connections, an additional 50,000 barrels of crude oil per day on average during each month occurring during the first seven years following satisfaction of such conditions, (iii) subject to certain conditions, including notice that transportation services on the EPIC pipeline are ready to commence and completion of certain infrastructure connections, an additional 50,000 barrels of crude oil per day on average during each month occurring during the first seven years following satisfaction of such conditions and (iv) such other volumes of crude oil as agreed by the parties. The Company is entitled to receive payment for such crude oil under netback pricing, whereby the price for the Company's crude oil is determined based on a formula which takes into consideration the final purchase price obtained by Vitol in marketing such crude oil in certain third party transactions less certain costs. In connection therewith, Vitol has agreed to, among other things, use commercially reasonable efforts to (i) maximize the final purchase price to the Company and mitigate any costs factored into the price determination and (ii) acquire third party crude oil to cover any shortfall below the Company's volumes commitments. Vitol also agrees to (i) use the same care and apply the same policies as it would exercise and apply if it were trading the subject crude oil for Vitol's own account and (ii) transport such crude oil on certain designated pipelines, including the Gray Oak pipeline pursuant to rights we have obtained through our Gray Oak transportation services agreement described below under third party shipper rights or term assignments, as applicable, prior to Vitol's downstream marketing activities.

Transportation Services Agreement with Gray Oak Pipeline, LLC

Pursuant to an addendum, dated as of August 13, 2018, to the transportation services agreement with Gray Oak Pipeline, LLC, dated as of April 23, 2018 (the "Gray Oak TSA 1"), Diamondback E&P LLC agreed to accelerated commissioning service ("ACS") on the Gray Oak pipeline in the amount of 50,000 barrels of crude oil per day. Under the ACS program, shippers must make a deficiency payment for any barrels not shipped during the ACS term, which expires the day before the Gray Oak pipeline goes into full service, which is currently anticipated to occur in the second quarter of 2020. The ACS commenced on November 12, 2019 and is ongoing. Due to restrictive API gravity provisions and the lack of markets, Diamondback E&P LLC has been unable to ship any volumes over the Gray Oak pipeline since the inception of ACS. This has resulted in Diamondback E&P LLC owing deficiency payments to Gray Oak Pipeline, LLC during 2019 in the aggregate amount of $11 million. The deficiency payment rate varies depending upon the month in which the deficiency occurs. Certain deficiencies can be used as a credit against volumes shipped in excess of a customer's minimum contract volume each quarter during the first two years of full service on the Gray Oak pipeline, subject to certain restrictions.

Once full service commences on the Gray Oak pipeline, subject to the terms and conditions of the Gray Oak TSA 1, Diamondback E&P LLC will be required to ship 50,000 barrels per day of crude oil on the Gray Oak pipeline or pay a deficiency payment for any shortfall in volumes as measured on a quarterly basis. Such deficiency payments can be used as a credit against future shipments in excess of our minimum contract volume each quarter, subject to certain restrictions.

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, 2019, 2018 and 2017 the Company paid $8 million, $2 million and $2 million, respectively, in contributions to the plan.

19. SUBSEQUENT EVENTS

Fourth Quarter 2019 Dividend Declaration

On February 14, 2020, the Board of Directors of the Company declared a cash dividend for the fourth quarter of 2019 of $0.3750 per share of common stock, payable on March 10, 2020 to its stockholders of record at the close of business on March 3, 2020.

Commodity Contracts

Subsequent to December 31, 2019, the Company entered into new fixed price swaps, fixed price basis swaps, three-way collars and put spreads. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on WTI and Crude Oil Brent and gas derivative settlements based on Waha Hub and Brent.

The following tables present the derivative contracts entered into by the Company subsequent to December 31, 2019. When aggregating multiple contracts, the weighted average contract price is disclosed.

	2020	
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
Oil Swaps - WTI Cushing	732,000	$ 60.50
Oil Swaps - BRENT	732,000	$ 65.00
Natural Gas Swaps - Waha Hub	1,840,000	$ 0.75
Natural Gas Basis Swaps - Waha Hub	13,750,000	$ (1.85)
Diesel Price Swaps	11,000,000	$ 1.60

	2020
Oil Three-Way Collars	**Brent**
Volume (Bbls)	732,000
Short put price (per Bbl)	$ 50.00
Floor price (per Bbl)	$ 60.00
Ceiling price (per Bbl)	$ 69.25

	2020
Oil Put Spreads - WTI	
Volume (Bbls)	829,125
Short put price (per Bbl)	$ 50.50
Floor price (per Bbl)	$ 60.50
Oil Put Spreads - Brent	
Volume (Bbls)	1,758,750
Short put price (per Bbl)	$ 52.38
Floor price (per Bbl)	$ 65.00

20. REPORT OF BUSINESS SEGMENTS

The Company reports its operations in two business segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas and (ii) the midstream operations segment includes midstream services and real estate. All of Rattler’s equity method investments are included in the midstream segment.

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

The following tables summarize the results of the Company's business segments during the periods presented:

	Upstream	Midstream Services	Eliminations	Total
Year Ended December 31, 2019:		(in millions)		
Third-party revenues	$ 3,891	$ 73	$ —	$ 3,964
Intersegment revenues	—	375	(375)	—
Total revenues	3,891	448	(375)	3,964
Depreciation, depletion and amortization	$ 1,405	$ 42	$ —	$ 1,447
Impairment of oil and natural gas properties	$ 790	$ —	$ —	$ 790
Income from operations	$ 790	$ 219	$ (314)	$ 695
Interest expense, net	$ (171)	$ (1)	$ —	$ (172)
Total other income (expense), net[(1)]	$ (320)	$ (7)	$ (6)	$ (333)
Provision for income taxes	$ 21	$ 26	$ —	$ 47
Net income attributable to non-controlling interest	$ 75	$ 91	$ (91)	$ 75
Net income attributable to Diamondback Energy	$ 374	$ 95	$ (229)	$ 240
Total assets	$ 22,125	$ 1,636	$ (230)	$ 23,531

(1) The impairment for the midstream services segment of $2 million is included in other income (expense).

	Upstream	Midstream Services	Eliminations	Total
Year Ended December 31, 2018:		(in millions)		
Third-party revenues	$ 2,132	$ 44	$ —	$ 2,176
Intersegment revenues	—	140	(140)	—
Total revenues	2,132	184	(140)	2,176
Depreciation, depletion and amortization	$ 598	$ 25	$ —	$ 623
Income from operations	$ 1,071	$ 80	$ (140)	$ 1,011
Interest expense, net	$ (87)	$ —	$ —	$ (87)
Total other income (expense), net	$ 102	$ —	$ —	$ 102
Provision for income taxes	$ 151	$ 17	$ —	$ 168
Net income attributable to non-controlling interest	$ 99	$ —	$ —	$ 99
Net income attributable to Diamondback Energy	$ 923	$ 63	$ (140)	$ 846
Total assets	$ 21,096	$ 604	$ (104)	$ 21,596

	Upstream	Midstream Services	Eliminations	Total
Year Ended December 31, 2017:	(in millions)			
Third-party revenues	$ 1,198	$ 7	$ —	$ 1,205
Intersegment revenues	—	32	(32)	—
Total revenues	1,198	39	(32)	1,205
Depreciation, depletion and amortization	$ 324	$ 3	$ —	$ 327
Income from operations	$ 613	$ 24	$ (32)	$ 605
Interest expense, net	$ (41)	$ —	$ —	$ (41)
Total other income (expense), net	$ (109)	$ 1	$ —	$ (108)
Provision for income taxes	$ (24)	$ 4	$ —	$ (20)
Net income attributable to non-controlling interest	$ 35	$ —	$ —	$ 35
Net income attributable to Diamondback Energy	$ 493	$ 21	$ (32)	$ 482
Total assets	$ 7,475	$ 300	$ (4)	$ 7,771

21. GUARANTOR FINANCIAL STATEMENTS

As of December 31, 2019, Diamondback O&G LLC is a guarantor under the indenture relating to the Series of Senior Notes. In connection with the satisfaction and discharge of the indenture governing the 2024 Senior Notes, Diamondback E&P LLC and Energen Corporation and its subsidiaries were released as guarantors under the 2024 Senior Notes, the 2025 Senior Notes and Diamondback O&G LLC’s revolving credit facility. Rattler LLC was released as a guarantor under Diamondback O&G LLC’s credit agreement on May 28, 2019. Viper, Viper’s General Partner, Viper LLC, Rattler, Rattler’s General Partner and Rattler’s subsidiaries remain Non-Guarantor Subsidiaries. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 21 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.

None of Rattler, Rattler’s General Partner or Rattler’s subsidiaries were guarantors under the 2024 Senior Notes, the 2025 Senior Notes or Diamondback O&G LLC’s revolving credit facility for the previous periods presented; therefore, the schedules that follow have been adjusted to reflect this correction of an immaterial change. Rattler LLC was a guarantor under Diamondback O&G LLC’s credit agreement until May 28, 2019.

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

Condensed Consolidated Balance Sheet
December 31, 2019
(In millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 93	$ —	$ 30	$ —	$ 123
Restricted cash	5	—	—	—	5
Accounts receivable, net	—	248	367	—	615
Intercompany receivable	5,331	—	572	(5,903)	—
Inventories	—	1	36	—	37
Derivative instruments	—	46	—	—	46
Prepaid expenses and other	2	1	21	19	43
Total current assets	5,431	296	1,026	(5,884)	869
Property and equipment:					
Oil and natural gas properties, full cost method of accounting	—	13,276	12,707	(201)	25,782
Midstream assets	—	—	931	—	931
Other property, equipment and land	—	—	125	—	125
Accumulated depletion, depreciation, amortization and impairment	—	(3,167)	(1,831)	(5)	(5,003)
Net property and equipment	—	10,109	11,932	(206)	21,835
Equity method investments	—	—	479	—	479
Derivative instruments	—	7	—	—	7
Investment in subsidiaries	10,414	—	—	(10,414)	—
Investment in real estate, net	—	—	109	—	109
Deferred tax asset	—	—	142	—	142
Other assets	—	10	310	(230)	90
Total assets	$ 15,845	$ 10,422	$ 13,998	$ (16,734)	$ 23,531
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ —	$ 179	$ —	$ 179
Intercompany payable	—	5,930	(27)	(5,903)	—
Accrued capital expenditures	—	—	475	—	475
Other accrued liabilities	17	132	155	—	304
Revenues and royalties payable	—	—	278	—	278
Derivative instruments	—	18	8	1	27
Total current liabilities	17	6,080	1,068	(5,902)	1,263
Long-term debt	3,769	13	1,589	—	5,371
Asset retirement obligations	—	34	60	—	94
Deferred income taxes	470	—	1,416	—	1,886
Other long-term liabilities	—	—	11	—	11
Total liabilities	4,256	6,127	4,144	(5,902)	8,625
Commitments and contingencies					
Stockholders’ equity	11,589	4,295	7,908	(10,543)	13,249
Non-controlling interest	—	—	1,946	(289)	1,657
Total equity	11,589	4,295	9,854	(10,832)	14,906
Total liabilities and equity	$ 15,845	$ 10,422	$ 13,998	$ (16,734)	$ 23,531

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

Condensed Consolidated Balance Sheet
December 31, 2018
(In millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 84	$ 2	$ 129	$ —	$ 215
Accounts receivable, net	—	143	249	—	392
Accounts receivable - related party	—	—	4	(4)	—
Intercompany receivable	4,469	—	201	(4,670)	—
Inventories	—	2	35	—	37
Derivative instruments	—	197	34	—	231
Prepaid expenses and other	2	—	48	—	50
Total current assets	4,555	344	700	(4,674)	925
Property and equipment:					
Oil and natural gas properties, full cost method of accounting	—	11,170	11,132	(3)	22,299
Midstream assets	—	21	679	—	700
Other property, equipment and land	—	1	146	—	147
Accumulated depletion, depreciation, amortization and impairment	—	(2,432)	(330)	(12)	(2,774)
Net property and equipment	—	8,760	11,627	(15)	20,372
Equity method investments	—	—	1	—	1
Investment in subsidiaries	12,689	—	112	(12,801)	—
Deferred tax asset	—	—	97	—	97
Investment in real estate, net	—	—	116	—	116
Other assets	—	10	75	—	85
Total assets	$ 17,244	$ 9,114	$ 12,728	$ (17,490)	$ 21,596
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ —	$ 128	$ —	$ 128
Intercompany payable	—	3,939	734	(4,673)	—
Accrued capital expenditures	—	—	495	—	495
Other accrued liabilities	14	23	216	—	253
Revenues and royalties payable	—	—	143	—	143
Total current liabilities	14	3,962	1,716	(4,673)	1,019
Long-term debt	2,036	1,490	938	—	4,464
Derivative instruments	—	11	4	—	15
Asset retirement obligations	—	30	106	—	136
Deferred income taxes	382	—	1,403	—	1,785
Other long-term liabilities	—	—	10	—	10
Total liabilities	2,432	5,493	4,177	(4,673)	7,429
Commitments and contingencies					
Stockholders' equity	14,812	3,621	7,856	(12,589)	13,700
Non-controlling interest	—	—	695	(228)	467
Total equity	14,812	3,621	8,551	(12,817)	14,167
Total liabilities and equity	$ 17,244	$ 9,114	$ 12,728	$ (17,490)	$ 21,596

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

Condensed Consolidated Statement of Operations
Year Ended December 31, 2019
(In millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 1,972	$ 1,318	$ 264	$ 3,554
Natural gas sales	—	27	31	8	66
Natural gas liquid sales	—	132	114	21	267
Royalty income	—	—	293	(293)	—
Lease bonus	—	—	4	—	4
Midstream services	—	—	434	(370)	64
Other operating income	—	—	14	(5)	9
Total revenues	—	2,131	2,208	(375)	3,964
Costs and expenses:					
Lease operating expenses	—	390	243	(143)	490
Production and ad valorem taxes	—	130	118	—	248
Gathering and transportation	—	75	34	(21)	88
Midstream services	—	—	170	(79)	91
Depreciation, depletion and amortization	—	735	720	(8)	1,447
Impairment of oil and natural gas properties	—	—	790	—	790
General and administrative expenses	48	1	67	(12)	104
Asset retirement obligation accretion	—	2	5	—	7
Other operating expense	—	—	4	—	4
Total costs and expenses	48	1,333	2,151	(263)	3,269
Income (loss) from operations	(48)	798	57	(112)	695
Other income (expense):					
Interest expense, net	(47)	(74)	(51)	—	(172)
Other income (expense), net	3	—	2	(7)	(2)
Gain on derivative instruments, net	—	(56)	(52)	—	(108)
Gain on revaluation of investment	—	—	5	—	5
Loss on extinguishment of debt	(56)	—	—	—	(56)
Income from subsidiaries	764	—	—	(764)	—
Total other income (expense), net	664	(130)	(96)	(771)	(333)
Income (loss) before income taxes	616	668	(39)	(883)	362
Provision for (benefit from) income taxes	81	—	(33)	(1)	47
Net income (loss)	535	668	(6)	(882)	315
Net income (loss) attributable to non-controlling interest	—	—	266	(191)	75
Net income (loss) attributable to Diamondback Energy, Inc.	$ 535	$ 668	$ (272)	$ (691)	$ 240

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

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

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 1,545	$ 87	$ 247	$ 1,879
Natural gas sales	—	43	5	13	61
Natural gas liquid sales	—	158	9	23	190
Royalty income	—	—	283	(283)	—
Lease bonus	—	—	6	(3)	3
Midstream services	—	—	172	(138)	34
Other operating income	—	—	9	—	9
Total revenues	—	1,746	571	(141)	2,176
Costs and expenses:					
Lease operating expenses	—	230	17	(42)	205
Production and ad valorem taxes	—	106	27	—	133
Gathering and transportation	—	41	1	(16)	26
Midstream services	—	—	72	—	72
Depreciation, depletion and amortization	—	472	134	17	623
General and administrative expenses	28	1	38	(2)	65
Merger and integration expense	18	—	18	—	36
Asset retirement obligation accretion	—	1	1	—	2
Other operating expenses	—	—	3	—	3
Total costs and expenses	46	851	311	(43)	1,165
Income (loss) from operations	(46)	895	260	(98)	1,011
Other income (expense):					
Interest expense, net	(43)	(20)	(24)	—	(87)
Other income (expense), net	1	—	90	(2)	89
Loss on derivative instruments, net	—	169	(68)	—	101
Gain on revaluation of investment	—	—	(1)	—	(1)
Income from subsidiaries	1,113	—	—	(1,113)	—
Total other expense, net	1,071	149	(3)	(1,115)	102
Income (loss) before income taxes	1,025	1,044	257	(1,213)	1,113
Provision for (benefit from) income taxes	241	—	(73)	—	168
Net income (loss)	784	1,044	330	(1,213)	945
Net income attributable to non-controlling interest	—	—	119	(20)	99
Net income (loss) attributable to Diamondback Energy, Inc.	$ 784	$ 1,044	$ 211	$ (1,193)	$ 846

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

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

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 904	$ —	$ 140	$ 1,044
Natural gas sales	—	43	—	9	52
Natural gas liquid sales	—	79	—	11	90
Royalty income	—	—	160	(160)	—
Lease bonus income	—	—	12	—	12
Midstream services	—	—	39	(32)	7
Total revenues	—	1,026	211	(32)	1,205
Costs and expenses:					
Lease operating expenses	—	143	—	(16)	127
Production and ad valorem taxes	—	63	11	—	74
Gathering and transportation	—	21	—	(8)	13
Midstream services	—	—	11	(1)	10
Depreciation, depletion and amortization	—	277	46	4	327
General and administrative expenses	27	—	23	(2)	48
Asset retirement obligation accretion expense	—	1	—	—	1
Total costs and expenses	27	505	91	(23)	600
Income (loss) from operations	(27)	521	120	(9)	605
Other income (expense):					
Interest expense, net	(30)	(6)	(5)	—	(41)
Other income (expense), net	1	—	12	(2)	11
Loss on derivative instruments, net	—	(77)	(1)	—	(78)
Income from subsidiaries	446	—	—	(446)	—
Total other expense, net	417	(83)	6	(448)	(108)
Income (loss) before income taxes	390	438	126	(457)	497
Provision for income taxes	(20)	—	—	—	(20)
Net income (loss)	410	438	126	(457)	517
Net income attributable to non-controlling interest	—	—	—	35	35
Net income (loss) attributable to Diamondback Energy, Inc.	$ 410	$ 438	$ 126	$ (492)	$ 482

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

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2019
(In millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used in) provided by operating activities	$ (956)	$ 1,433	$ 2,257	$ —	$ 2,734
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(2,038)	(639)	—	(2,677)
Additions to midstream assets	—	(38)	(206)	—	(244)
Purchase of other property, equipment and land	—	—	(5)	—	(5)
Acquisition of leasehold interests	—	(360)	(83)	—	(443)
Acquisition of mineral interests	—	—	(523)	190	(333)
Proceeds from sale of assets	—	118	372	(190)	300
Investment in real estate	—	—	(1)	—	(1)
Equity investments	—	—	(485)	—	(485)
Intercompany transfers	(860)	—	860	—	—
Net cash used in investing activities	(860)	(2,318)	(710)	—	(3,888)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	1,292	1,058	—	2,350
Repayment under credit facility	—	(2,769)	(949)	—	(3,718)
Proceeds from senior notes	2,968	—	501	—	3,469
Repayment of senior notes	(1,250)	—	—	—	(1,250)
Premium on extinguishment of debt	(44)	—	—	—	(44)
Proceeds from joint venture	—	—	39	—	39
Debt issuance costs	—	—	(18)	—	(18)
Public offering costs	—	—	(41)	—	(41)
Proceeds from public offerings	—	—	1,106	—	1,106
Distributions from subsidiary	860	—	—	(860)	—
Proceeds from exercise of stock options	9	—	—	—	9
Repurchased for tax withholdings	(13)	—	—	—	(13)
Repurchased as part of share buyback	(593)	—	—	—	(593)
Dividends to stockholders	(112)	—	—	—	(112)
Distributions to non-controlling interest	—	—	(982)	860	(122)
Intercompany transfers	—	2,360	(2,360)	—	—
Net cash (used in) provided by financing activities	1,825	883	(1,646)	—	1,062
Net increase (decrease) in cash and cash equivalents	9	(2)	(99)	—	(92)
Cash and cash equivalents at beginning of period	84	2	129	—	215
Cash and cash equivalents at end of period	$ 93	$ —	$ 30	$ —	$ 123

Table of Contents

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

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ (58)	$ 1,224	$ 399	$ —	$ 1,565
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(1,461)	—	—	(1,461)
Additions to midstream assets	—	(21)	(183)	—	(204)
Purchase of other property, equipment and land	—	(7)	—	—	(7)
Acquisition of leasehold interests	—	(1,371)	—	—	(1,371)
Acquisition of mineral interests	—	—	(440)	—	(440)
Proceeds from sale of assets	—	79	1	—	80
Investment in real estate	—	—	(111)	—	(111)
Funds held in escrow	—	27	(16)	—	11
Intercompany transfers	(367)	989	(622)	—	—
Net cash used in investing activities	(367)	(1,765)	(1,371)	—	(3,503)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	1,960	692	—	2,652
Repayment under credit facility	—	(867)	(375)	—	(1,242)
Repayment on Energen's credit facility	—	—	(559)	—	(559)
Proceeds from senior notes	1,062	—	—	—	1,062
Debt issuance costs	(14)	—	(11)	—	(25)
Public offering costs	—	—	(3)	—	(3)
Proceeds from public offerings	—	—	305	—	305
Contributions to subsidiaries	(1)	—	(1)	2	—
Distribution to parent	155	—	—	(155)	—
Distributions from subsidiary	(696)	—	696	—	—
Repurchased for tax withholdings	(14)	—	—	—	(14)
Dividends to stockholders	(37)	—	—	—	(37)
Distributions to non-controlling interest	—	—	(253)	155	(98)
Intercompany transfers	—	(550)	552	(2)	—
Net cash provided by financing activities	455	543	1,043	—	2,041
Net increase (decrease) in cash and cash equivalents	30	2	71	—	103
Cash and cash equivalents at beginning of period	54	—	58	—	112
Cash and cash equivalents at end of period	$ 84	$ 2	$ 129	$ —	$ 215

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

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

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (29)	$ 768	$ 150	$ —	$ 889
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(790)	(3)	—	(793)
Additions to midstream assets	—	—	(68)	—	(68)
Purchase of other property, equipment and land	—	(22)	(1)	—	(23)
Acquisition of leasehold interests	—	(1,961)	—	—	(1,961)
Acquisition of mineral interests	—	(63)	(344)	—	(407)
Acquisition of midstream assets	—	—	(50)	—	(50)
Proceeds from sale of assets	—	66	—	—	66
Funds held in escrow	—	(27)	131	—	104
Intercompany transfers	(1,631)	1,631	—	—	—
Net cash used in investing activities	(1,631)	(1,166)	(335)	—	(3,132)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	475	279	—	754
Repayment under credit facility	—	(78)	(306)	—	(384)
Purchase of subsidiary units by parent	(10)	—	—	10	—
Debt issuance costs	(8)	1	(2)	—	(9)
Public offering costs	—	—	(1)	—	(1)
Proceeds from public offerings	—	—	380	(10)	370
Distribution from subsidiary	90	—	(1)	(89)	—
Distribution to non-controlling interest	—	—	(130)	89	(41)
Net cash provided by financing activities	72	398	219	—	689
Net increase (decrease) in cash and cash equivalents	(1,588)	—	34	—	(1,554)
Cash and cash equivalents at beginning of period	1,642	—	24	—	1,666
Cash and cash equivalents at end of period	$ 54	$ —	$ 58	$ —	$ 112

22. 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,	
	2019	2018
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 16,575	$ 12,629
Unproved properties	9,207	9,670
Total oil and natural gas properties	25,782	22,299
Accumulated depreciation, depletion, amortization	(2,995)	(1,599)
Accumulated impairment	(1,934)	(1,144)
Net oil and natural gas properties capitalized	$ 20,853	$ 19,556

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,		
	2019	2018	2017
	(In millions)		
Acquisition costs:			
Proved properties	$ 194	$ 5,665	$ 455
Unproved properties	418	5,818	2,692
Development costs	956	493	145
Exploration costs	1,915	1,090	780
Total	$ 3,483	$ 13,066	$ 4,072

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, natural gas and natural gas liquids. It does not include any interest costs or general and administrative costs and it reflects estimated corporate income taxes at enacted tax rates expected to be applicable the Company. Therefore, the following schedule is not necessarily indicative of the contribution to the net operating results of the Company's oil, natural gas and natural gas liquids operations.

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Oil, natural gas and natural gas liquid sales	$ 3,887	$ 2,130	$ 1,186
Lease operating expenses	(490)	(205)	(127)
Production and ad valorem taxes	(248)	(133)	(74)
Gathering and transportation	(88)	(26)	(13)
Depreciation, depletion, and amortization	(1,447)	(595)	(321)
Impairment	(790)	—	—
Asset retirement obligation accretion expense	(7)	(2)	(1)
Income tax benefit (expense)	(89)	(241)	20
Results of operations	$ 728	$ 928	$ 670

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2019, 2018 and 2017 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.

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, 2017	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
Extensions and discoveries	256,569	66,572	318,874
Revisions of previous estimates	(84,789)	(8,166)	(149,657)
Purchase of reserves in place	13,974	3,813	19,830
Divestitures	(33,269)	(3,809)	(21,272)
Production	(68,518)	(18,498)	(97,613)
As of December 31, 2019	710,903	230,203	1,118,811
Proved Developed Reserves:			
January 1, 2017	79,457	22,080	105,399
December 31, 2017	141,246	35,412	190,740
December 31, 2018	403,051	125,509	705,084
December 31, 2019	457,083	165,173	824,760
Proved Undeveloped Reserves:			
January 1, 2017	59,717	15,054	69,497
December 31, 2017	91,935	19,198	94,629
December 31, 2018	223,885	64,782	343,565
December 31, 2019	253,820	65,030	294,051

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, 2019, the Company’s extensions and discoveries totaling 376,287 MBOE resulted primarily from the drilling of 283 new wells and from 291 new proved undeveloped locations added in which the Company owns a working interest. Viper royalty interests accounted for 5% of the extension volumes. The Company’s downward revisions of 117,898 MBOE were the result of proved undeveloped downgrades associated with inventory refinement following the Energen acquisition along with updated development plans and lower realized prices. Purchases of 21,092 MBOE were the result of 10,939 MBOE of working interest purchases and 10,153 MBOE of Viper royalty purchases, excluding mineral interests dropped down to Viper.

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. Viper 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 Viper 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. Viper royalty interests 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 Viper royalty interest purchases accounted for 10%, with working interest purchases contributing the remainder.

At December 31, 2019, the Company’s estimated PUD reserves were approximately 367,859 MBOE, a 21,931 MBOE increase over the reserve estimate at December 31, 2018 of 345,928 MBOE. The following table includes the changes in PUD reserves for 2019:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2018	345,928
Undeveloped reserves transferred to developed	(120,920)
Revisions	(77,519)
Net purchases	4,542
Divestitures	(5,672)
Extensions and discoveries	221,500
Ending proved undeveloped reserves at December 31, 2019	367,859

The increase in proved undeveloped reserves was primarily attributable to extensions of 213,909 MBOE from 291 gross (262 net) wells in which the Company has a working interest and 7,591 MBOE from 97 gross wells in which Viper owns royalty interests. Of the 291 gross working interest wells, 64 were in the Delaware Basin. Transfers of 120,920 MBOE were the result of drilling or participating in 135 gross (119 net) horizontal wells in which the Company has a working interest and 79 gross wells in which the Company has a royalty interest or mineral interest through Viper. The Company owns a working interest in 75 of the 79 gross Viper wells. Downward revisions of 77,519 MBOE resulted from 67,114 MBOE of PUD downgrades due to refinement of the PUD inventory following the acquisition of Energen. These downgrades were offset with Extensions. The remaining 10,405 MOE of downward revisions were mostly from lower benchmark commodity prices.

As of December 31, 2019, all of the Company’s proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2019, approximately $956 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.

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, 2019, 2018 and 2017.

	December 31,		
	2019	2018	2017
	(In millions)		
Future cash inflows	$ 40,681	$ 43,578	$ 12,922
Future development costs	(3,809)	(3,560)	(1,124)
Future production costs	(9,319)	(7,727)	(2,995)
Future production taxes	(2,905)	(2,935)	(929)
Future income tax expenses	(2,635)	(3,913)	(84)
Future net cash flows	22,013	25,443	7,790
10% discount to reflect timing of cash flows	(11,829)	(13,767)	(4,033)
Standardized measure of discounted future net cash flows	$ 10,184	$ 11,676	$ 3,757

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,		
	2019	2018	2017
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 51.88	$ 59.63	$ 48.03
Natural gas (per Mcf)	$ 0.18	$ 1.47	$ 2.06
Natural gas liquids (per Bbl)	$ 15.65	$ 24.43	$ 20.79

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,		
	2019	2018	2017
	(In millions)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 11,676	$ 3,757	$ 1,711
Sales of oil and natural gas, net of production costs	(3,334)	(1,786)	(986)
Acquisition of reserves	309	5,520	439
Divestiture of reserves	(500)	(2)	(11)
Extensions and discoveries, net of future development costs	4,004	3,287	1,792
Previously estimated development costs incurred during the period	120	535	190
Net changes in prices and production costs	831	1,805	578
Changes in estimated future development costs	(3,190)	(81)	(53)
Revisions of previous quantity estimates	(1,242)	271	(99)
Accretion of discount	1,344	380	174
Net change in income taxes	693	(1,728)	(9)
Net changes in timing of production and other	(527)	(282)	31
Standardized measure of discounted future net cash flows at the end of the period	$ 10,184	$ 11,676	$ 3,757

23. QUARTERLY FINANCIAL DATA (Unaudited)

The Company’s unaudited quarterly financial data for 2019 and 2018 is summarized below.

	2019			
(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 864	$ 1,021	$ 975	$ 1,104
Income (loss) from operations	319	411	349	(384)
Income tax expense (benefit)	(33)	102	102	(124)
Net income (loss)	43	356	388	(472)
Net income attributable to non-controlling interest	33	7	20	15
Net income (loss) attributable to Diamondback Energy, Inc.	$ 10	$ 349	$ 368	$ (487)
Earnings per common share				
Basic	$ 0.06	$ 2.12	$ 2.27	$ (3.04)
Diluted	$ 0.06	$ 2.11	$ 2.26	$ (3.04)

	2018			
(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 479	$ 527	$ 537	$ 633
Income from operations	267	281	268	195
Income tax expense (benefit)	47	(7)	43	85
Net income	178	301	160	306
Net income attributable to non-controlling interest	15	82	3	(1)
Net income attributable to Diamondback Energy, Inc.	$ 163	$ 219	$ 157	$ 307
Earnings per common share				
Basic	$ 1.65	$ 2.22	$ 1.59	$ 2.50
Diluted	$ 1.65	$ 2.22	$ 1.59	$ 2.50

Exhibit 4.1

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of common stock of Diamondback Energy, Inc. (the "Company," "we," "us," and "our"), which is the only class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following summary is not complete. You should refer to the applicable provisions of our Amended and Restated Certificate of Incorporation and the Certificate of Amendment No. 1 of the Amended and Restated Certificate of Incorporation and any subsequent amendments thereto (collectively, "our certificate of incorporation"), our Amended and Restated Bylaws, the First Amendment to our Amended and Restated Bylaws and any subsequent amendments thereto (collectively, "our bylaws") and the Delaware General Corporation Law (the "DGCL") for a complete statement of the terms and rights of our common stock. Copies of our Amended and Restated Certificate of Incorporation, Amendment No. 1 thereto, our Amended and Restated Bylaws and the First Amendment thereto have been filed with the Securities and Exchange Commission as exhibits 3.1, 3.2, 3.3 and 3.4, respectively, to our Annual Report on Form 10-K.

Authorized Capital Stock

Our authorized capital stock consists of 200,000,000 shares of common stock, par value $0.01 per share, and 10,000,000 shares of preferred stock, par value $0.01 per share.

Common Stock

Holders of shares of common stock are entitled to one vote per share on all matters submitted to a vote of stockholders. Shares of common stock do not have cumulative voting rights, which means that the holders of more than 50% of the shares voting for the election of the board of directors can elect all the directors to be elected at that time, and, in such event, the holders of the remaining shares will be unable to elect any directors to be elected at that time. Our certificate of incorporation denies stockholders any preemptive rights to acquire or subscribe for any stock, obligation, warrant or other securities of ours. Holders of shares of our common stock have no redemption or conversion rights nor are they entitled to the benefits of any sinking fund provisions.

In the event of our liquidation, dissolution or winding up, holders of shares of common stock shall be entitled to receive, pro rata, all the remaining assets of our company available for distribution to our stockholders after payment of our debts and after there shall have been paid to or set aside for the holders of capital stock ranking senior to common stock in respect of rights upon liquidation, dissolution or winding up the full preferential amounts to which they are respectively entitled.

Holders of record of shares of common stock are entitled to receive dividends when and if declared by the board of directors out of any assets legally available for such dividends, subject to both the rights of all outstanding shares of capital stock ranking senior to the common stock in respect of dividends and to any dividend restrictions contained in debt agreements. All outstanding shares of common stock and any shares sold and issued in this offering will be fully paid and nonassessable by us. As of February 14, 2020, there were 158,284,486 shares of our common stock outstanding.

Preferred Stock

Our board of directors is authorized to issue up to 10,000,000 shares of preferred stock in one or more series. The board of directors may fix for each series:

- the distinctive serial designation and number of shares of the series;
- the voting powers and the right, if any, to elect a director or directors;
- the terms of office of any directors the holders of preferred shares are entitled to elect;
- the dividend rights, if any;
- the terms of redemption, and the amount of and provisions regarding any sinking fund for the purchase or redemption thereof;
- the liquidation preferences and the amounts payable on dissolution or liquidation;
- the terms and conditions under which shares of the series may or shall be converted into any other series or class of stock or debt of the corporation; and
- any other terms or provisions which the board of directors is legally authorized to fix or alter.

We do not need stockholder approval to issue or fix the terms of the preferred stock. The actual effect of the authorization of the preferred stock upon your rights as holders of common stock is unknown until our board of directors determines the specific rights of owners of any series of preferred stock. Depending upon the rights granted to any series of preferred stock, your voting power, liquidation preference or other rights could be adversely affected. Preferred stock may be issued in acquisitions or for other corporate purposes. Issuance in connection with a stockholder rights plan or other takeover defense could have the effect of making it more difficult for a third party to acquire, or of discouraging a third party from acquiring, control of our company. We currently have no outstanding preferred stock and have no present plans to issue any shares of preferred stock.

Related Party Transactions and Corporate Opportunities

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 so long as it has been approved by our board of directors;
- permits certain of our stockholders, officers and directors, including our non-employee 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 certain of our officers or directors, including our non-employee directors, becomes aware of a potential business opportunity,

transaction or other matter (other than one expressly offered to that director or officer 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 any other entity or individual and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary duty to us or our stockholders regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

Anti-takeover Effects of Provisions of Our Certificate of Incorporation and Our Bylaws

Some provisions of our certificate of incorporation and our bylaws contain provisions that could make it more difficult to acquire us by means of a merger, tender offer, proxy contest or otherwise, or to remove our incumbent officers and directors. These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of increased protection of our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging such proposals because negotiation of such proposals could result in an improvement of their terms.

Undesignated preferred stock. The ability to authorize and issue undesignated preferred stock may enable our board of directors to render more difficult or discourage an attempt to change control of us by means of a merger, tender offer, proxy contest or otherwise. For example, if in the due exercise of its fiduciary obligations, the board of directors were to determine that a takeover proposal is not in our best interest, the board of directors could cause shares of preferred stock to be issued without stockholder approval in one or more private offerings or other transactions that might dilute the voting or other rights of the proposed acquirer or insurgent stockholder or stockholder group.

Stockholder meetings. Our certificate of incorporation and bylaws provide that a special meeting of stockholders may be called only by the Chairman of the Board, the Chief Executive Officer or by a resolution adopted by a majority of our board of directors, assuming there are no vacancies.

Requirements for advance notification of stockholder nominations and proposals. Our bylaws establish advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors, other than nominations made by or at the direction of the board of directors.

Stockholder action by written consent. Our certificate of incorporation provides that, except as may otherwise be provided with respect to the rights of the holders of preferred stock, no action that is required or permitted to be taken by our stockholders at any annual or special meeting may be effected by written consent of stockholders in lieu of a meeting of stockholders, unless the action to be effected by written consent of stockholders and the taking of such action by such written consent have expressly been approved in advance by our board. This provision, which may not be amended except by the affirmative vote of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class, makes it difficult for stockholders to initiate or effect an action by written consent that is opposed by our board.

Amendment of the bylaws. Under Delaware law, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our certificate of incorporation and bylaws grant our board the power to adopt, amend and repeal our bylaws at any regular or special meeting of the board on the affirmative vote of a majority of the directors, assuming there are no vacancies. Our stockholders may adopt, amend or repeal our bylaws but only at any regular or special meeting of stockholders by an affirmative vote of holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class.

Removal of Director. Our certificate of incorporation provide that members of our board of directors may only be removed by the affirmative vote of holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class.

Amendment of the Certificate of Incorporation. Our certificate of incorporation provides that, in addition to any other vote that may be required by law or any preferred stock designation, the affirmative vote of the holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class, is required to amend, alter or repeal, or adopt any provision as part of our certificate of incorporation inconsistent with the provisions of our certificate of incorporation dealing with distributions on our common stock, related party transactions, our board of directors, our bylaws, meetings of our stockholders or amendment of our certificate of incorporation.

Additionally, an increase in the number of authorized shares of our common stock, could be used to make it more difficult to, or discourage an attempt to, obtain control of our company by means of a takeover bid that our board of directors determines is not in our best interests or the best interests of our stockholders. However, our board of directors does not intend or view the proposed increase in authorized common stock as an anti-takeover measure and did not propose the increase in response to any attempt or plan to obtain control of the company.

The provisions of our certificate of incorporation and bylaws could have the effect of discouraging others from attempting hostile takeovers and, as a consequence, they may also inhibit temporary fluctuations in the market price of our common stock that often result from actual or rumored hostile takeover attempts. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish transactions which stockholders may otherwise deem to be in their best interests.

Choice of Forum

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will be the sole and exclusive forum for: (i) any derivative action or proceeding brought on our behalf; (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders; (iii) any action asserting a claim against us arising pursuant to any provision of the DGCL or our certificate of incorporation or bylaws; or (iv) any action asserting a claim against us pertaining to internal affairs of our corporation. Our certificate of incorporation also provides that any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of and to have consented to this choice of forum provision. It is possible that a court of law could rule that the choice of forum provision contained in our certificate of incorporation is inapplicable or unenforceable if it is challenged in a proceeding or otherwise.

Listing

Our common stock is listed on The Nasdaq Global Select Market under the symbol “FANG.”

Transfer Agent and Registrar

Computershare Trust Company, N.A. is the transfer agent and registrar for our common stock.

Exhibit 10.2

Restricted Stock Unit Award (#) O-RSU20-___

DIAMONDBACK ENERGY, INC.
2019 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD CERTIFICATE

THIS IS TO CERTIFY that Diamondback Energy, Inc., a Delaware corporation (the ***"Company"***), has granted you (***"Participant"***) hypothetical units of Common Stock ("***Restricted Stock Units***") under the Company's 2019 Amended and Restated Equity Incentive Plan (the ***"Plan"***), as follows:

Name of Participant:	________________
Total Number of Restricted Stock Units Granted:	_____________
Date of Grant:	________, 2020
Vesting Schedule and Payment/Settlement Dates:	Shares of common stock will vest on the Vesting Dates specified below and will be settled within 10 business days after each Vesting Date specified below.

Vesting Date	**# Vested Shares**
________, 2020	_______
________, 2021	_______
________, 2022	_______

By your signature and the signature of the Company's representative below, you and the Company agree to be bound by all of the terms and conditions of the Restricted Stock Unit Award Agreement attached hereto as *Annex I*, and the Plan (both incorporated herein by this reference as if set forth in full in this document). By executing this Certificate, you hereby irrevocably elect to accept the Restricted Stock Unit rights granted pursuant to this Certificate and the related Restricted Stock Unit Award Agreement and to receive the Restricted Stock Units designated above subject to the terms of the Plan, this Certificate, and the Restricted Stock Unit Award Agreement.

PARTICIPANT	**DIAMONDBACK ENERGY, INC.**
By: [Name] Dated: ______ __, 2020	By: Travis D. Stice, Chief Executive Officer Dated: _____ __, 2020

DIAMONDBACK ENERGY, INC.
2019 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD AGREEMENT

This Restricted Stock Unit Award Agreement (this "***Agreement***"), is made and entered into on the execution date of the Restricted Stock Unit Award Certificate to which it is attached (the ***"Certificate"***), by and between Diamondback Energy, Inc., a Delaware corporation (the ***"Company"***), and the **Participant** named in the Certificate.

Pursuant to the Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan (the ***"Plan"***), the Administrator has authorized the grant to Participant of the number of Restricted Stock Units set forth in the Certificate (the "***Award***"), upon the terms and subject to the conditions set forth in this Agreement and in the Plan. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan.

NOW, **THEREFORE**, in consideration of the premises and the benefits to be derived from the mutual observance of the covenants and promises contained herein and other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

1. Basis for Award. This Award is made pursuant to Section 7.1 of the Plan for valid consideration provided to the Company by Participant. By Participant's execution of the Certificate, Participant agrees to accept the Award rights granted pursuant to the Certificate and this Agreement, and to receive the Restricted Stock Units designated in the Certificate subject to the terms of the Plan, the Certificate, and this Agreement.

2. Restricted Stock Units Awarded.

2.1 The Company hereby grants to Participant the number of Restricted Stock Units set forth in the Certificate. Each Restricted Stock Unit represents a right to receive one share of Common Stock from the Company payable in accordance with Section 5 below and any Dividend Equivalents (as defined below) credited to the Participant's Restricted Stock Unit Account (as defined below) with respect to that share.

2.2 The Company will, in accordance with the Plan, establish and maintain an account (the "***Restricted Stock Unit Account***") for Participant, and will credit such account for the number of Restricted Stock Units granted to Participant and any Dividend Equivalents as provided in Section 4 below. On any given date, the value of each Restricted Stock Unit will equal the Fair Market Value on such date of one share of Common Stock.

3. Vesting.

3.1 The Restricted Stock Units will vest pursuant to the Vesting Schedule set forth in the Certificate. Except as otherwise provided in an employment agreement, severance plan participation agreement or other service agreement between the Participant and the Company or an Affiliate (a "***Service Agreement***") or as provided in Sections 3.2, 3.3 or 3.4 below, if Participant ceases Continuous Service for any reason, Participant will immediately forfeit the unvested Restricted Stock Units and any securities, other property or amounts nominally credited to the Restricted Stock Unit Account, including any Dividend Equivalents credited to the Restricted Stock Unit Account that have not been settled or paid.

3.2 Except as otherwise provided in a Service Agreement, in the event of Participant's involuntary termination of employment (other than for Cause, or on account of death or Disability) or resignation for Good Reason, in either case, in connection with the consummation of or within 24 months after the occurrence of a Change in Control (as defined in the Plan), (an "***Acceleration Event***"), with respect to any Restricted Stock Units then outstanding under this Award, the Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will vest immediately upon the occurrence of an Acceleration Event and will be settled upon the consummation of such Acceleration Event.

3.3 Except as otherwise provided in a Service Agreement, in the event of the Participant's death or Disability during a period of Continuous Service, the deceased or Disabled Participant's Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will become 100% vested. Participant's Restricted Stock Units and unpaid Dividend Equivalents will be settled and paid in full within 10 business days following the date of vesting.

3.4 To the extent that a Service Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service that is more favorable to Participant than the provisions of this Agreement, such provisions are incorporated by reference in this Agreement.

3.5 For purposes of this Agreement, "***Good Reason***" means Participant's resignation in the event of any (a) material reduction in Participant's base salary, bonus opportunity or severance benefits; (b) relocation of Participant's principal office more than 25 miles from the current location, or (c) material diminution in the Participant's position, duties, reporting relationship or authority, which in any case is not cured within thirty (30) business days after written notice thereof by you to the Board (which notice must be provided by you to the Company within 90 days following the initial occurrence of such event) and an opportunity to cure within the notice period (the "***Cure Period***"). Resignation by the Participant following the Employer's cure or before the expiration of the Cure Period will constitute a voluntary resignation and not a termination or resignation for Good Reason and will not entitle the Participant to any benefits under this Plan. Any termination on account of a Good Reason Resignation must occur within 120 days following the initial occurrence of such event.

4. Dividend Equivalents. If the Company pays any cash dividend on its outstanding Common Stock for which the record date occurs after the Date of Grant, the Administrator will credit the Restricted Stock Unit Account as of the dividend payment date in an amount equal to the amount of the dividend paid by the Company on a single Share multiplied by the number of Restricted Stock Units under this Agreement that are unvested as of that record date and that are vested but have not been settled under the payment terms of Section 5 ("***Dividend Equivalents***"). Except as otherwise provided in Section 3, Dividend Equivalents will vest and be paid to the Participant on the dividend payment date if Participant is in Continuous Service on the dividend payment date declared by the Company.

5. Payment/Settlement. Subject to Participant's satisfaction of the applicable withholding requirements pursuant to Section 7 hereof, the Company will settle the Award on the Payment/Settlement Date or Dates set forth in the Certificate by issuing to Participant one share of Common Stock for each Restricted Stock Unit payable on that Payment/Settlement Date (and upon such settlement, the Restricted Stock Units will cease to be credited to the Restricted Stock Unit Account). If the Certificate does not specify a Payment/Settlement Date, the applicable Payment/Settlement Date will be within 10 business days after each vesting date set forth in the Vesting Schedule. If an Acceleration Event occurs, the Payment/Settlement Date will be the date the Acceleration Event occurs. The Administrator will enter Participant's name as a stockholder of record with respect to such shares of Common Stock on the books of the Company with respect to the shares of Common Stock issued on that Payment/Settlement Date free of all restrictions hereunder, except for applicable federal and state securities law restrictions. Participant acknowledges and agrees that shares of Common Stock may be issued in electronic form as a book entry with the Company's transfer agent and that no physical certificates need be issued. Any securities, other property or amounts nominally credited to the Restricted Stock Unit Account other than Restricted Stock Units will be paid in kind or, in the Administrator's discretion, in cash. Dividend Equivalents will vest and be paid to the Participant on the dividend payment date if Participant is in Continuous Service on the dividend payment date declared by the Company. To the extent that a Service Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service, such provisions are incorporated by reference in this Agreement.

6. Compliance with Laws and Regulations. The issuance and transfer of shares of Common Stock on any Payment/Settlement Date will be subject to the Company's and Participant's full compliance, to the satisfaction of the Company and its counsel, with all applicable requirements of federal, state, and foreign securities laws and with all applicable requirements of any securities exchange on which the Common Stock may be listed at the time of such issuance or transfer. Participant understands that the Company is under no obligation to register or qualify the shares of Common Stock with the U.S. Securities and Exchange Commission ("***SEC***"), any state securities commission, foreign securities regulatory authority, or any securities exchange to effect such compliance.

7. Tax Withholding.

7.1 As a condition to payment under Section 5 hereof, Participant agrees that on or before the date as of which any portion of the Restricted Stock Units vest, Participant will pay to the Company any federal, state, or local taxes required by law to be withheld with respect to the Restricted Stock Units for which the restrictions lapse and any related securities, other property or amounts then nominally credited to the Restricted Stock Unit Account.

7.2 Participant will pay the amounts due under this Section 7 to the Company. Such amounts will be paid by Stock Withholding or may be paid, at Participant's election, in cash, or (to the extent any applicable insider trading policy, window or restriction does not prohibit Participant from engaging in a sale transaction) by tendering shares of Common Stock held by Participant to a broker selected by the Company for immediate sale and remittance of proceeds equal to the required withholding amount to the Company, including shares that otherwise would be issued and transferred to Participant as payment on the applicable Payment/Settlement Date, with a Fair Market Value on that Payment/Settlement Date that does not exceed the maximum statutory tax rates in the applicable jurisdictions (subject to the Participant's written request to withhold more than the required regular tax withholding in the applicable jurisdictions), or a combination of cash and shares of Common Stock. If Participant fails to make such payments, the Company or its Affiliates will, to the extent permitted by law, have the right to deduct from any payment of any kind otherwise due to Participant any federal, state, or local taxes required by law to be withheld with respect to such payment. Dividend Equivalents credited to the Restricted Stock Unit Account will be subject to withholding at the time of payment.

8. Not Transferrable. Until the applicable Payment/Settlement Date, the Restricted Stock Units, any related Dividend Equivalents credited to the Restricted Stock Unit Account and any related securities, other property or amounts nominally credited to the Restricted Stock Unit Account may not be sold, transferred, or otherwise disposed of, and may not be pledged or otherwise hypothecated other than by will or by the applicable laws of descent and distribution, provided that the Restricted Stock Units and any related Dividend Equivalents credited to the Restricted Stock Unit Account will remain subject to the terms of the Plan, the Certificate and this Agreement.

9. No Right to Continued Service. Nothing in this Agreement or in the Plan imposes or may be deemed to impose, by implication or otherwise, any limitation on any right of the Company or any Affiliate to terminate Participant's Continuous Service at any time.

10. Participant's Representations and Warranties. Participant represents and warrants to the Company that Participant has received a copy of the Plan, has read and understands the terms of the Plan, the Certificate, and this Agreement, and agrees to be bound by their terms and conditions. Participant acknowledges that there may be tax consequences upon the payment of the Restricted Stock Units, disposition of any shares of Common Stock received on a Payment/Settlement Date or payment of any Dividend Equivalents credited to the Restricted Stock Unit Account, and that Participant should consult a tax advisor before such time. Participant agrees to sign such additional documentation as the Company may reasonably require from time to time. Participant acknowledges that he or she is aware that copies of the Plan document and the Company's financial statements and information heretofore filed by the Company with the Securities and Exchange Commission (the "***SEC***") are available upon request to the Company, at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549, or by visiting the SEC Internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC.

11. No Interest in Company Assets. All amounts nominally credited to Participant's Restricted Stock Unit Account under this Agreement will continue for all purposes to be part of the general assets of the Company. Participant's interest in the

Restricted Stock Unit Account will make Participant only a general, unsecured creditor of the Company.

12. No Stockholder Rights before Delivery. Participant will not have any right, title, or interest in, or be entitled to vote or to receive distributions in respect of, or otherwise be considered the owner of, any of the shares of Common Stock covered by the Restricted Stock Units until the Payment/Settlement Dates specified in the Certificate at which such shares of Common Stock are issued pursuant to Section 5 hereof.

13. Modification. The Agreement may not be amended or otherwise modified except in writing signed by both parties.

14. Interpretation. Any dispute regarding the interpretation of this Agreement must be submitted by Participant or the Company to the Administrator for review. The resolution of such a dispute by the Administrator will be final and binding on the Company and Participant.

15. Entire Agreement. The Plan and the Certificate are incorporated herein by reference. This Agreement, the Certificate, and the Plan constitute the entire agreement of the parties and supersede all prior undertakings and agreements with respect to the subject matter hereof. If any inconsistency or conflict exists between the terms and conditions of this Agreement, the Certificate, and the Plan, the Plan will govern.

16. Successors and Assigns. The Company may assign any of its rights under this Agreement. This Agreement will bind and inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth herein, this Agreement is binding upon Participant and Participant's heirs, executors, administrators, legal representatives, successors, and assigns.

17. Governing Law. This Agreement will be governed by and construed in accordance with the laws of the State of Delaware without giving effect to its conflict of law principles. If any provision of this Agreement is determined by a court of law to be illegal or unenforceable, then such provision will be enforced to the maximum extent possible and the other provisions will remain fully effective and enforceable.

EXHIBIT A

Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan

Exhibit 10.3

Restricted Stock Unit Award (#) O-PSU20-___

DIAMONDBACK ENERGY, INC.
2019 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD CERTIFICATE

THIS IS TO CERTIFY that Diamondback Energy, Inc., a Delaware corporation (the ***"Company"***), has granted you (***"Participant"***) hypothetical units of Common Stock ("***Restricted Stock Units***") under the Company's 2019 Amended and Restated Equity Incentive Plan (the ***"Plan"***), as follows:

Name of Participant:	____________________
Target Number of Restricted Stock Units Granted:	________
Date of Grant:	________, 2020
Payment/Settlement Dates:	Fully vested Restricted Stock Units will be settled by the payment of shares of Common Stock within 10 business days after the date on which the Compensation Committee of the Board has made the certification required under Plan Section 7.2(d) with respect to the performance goals applicable to such Restricted Stock Units following the date of publication of the Corporation's quarterly earnings statement for the twelfth (12th) full quarter following the commencement of the Performance Period (which in any event will be no later than March 15 of the calendar year following the date such performance goals are achieved).
Performance Period:	January 1, 2020 through December 31, 2022
Performance Vesting Goals and Schedule:	The actual number of Restricted Stock Units with respect to which Participant will be entitled to receive shares of Common Stock will equal the product of (i) the Target Grant Vesting Percentage, multiplied by (ii) the Target Number of Restricted Stock Units Granted, multiplied by (iii) the Absolute TSR Modifier. The Target Grant Vesting Percentage will be determined based on the attainment of (i) Continuous Service through the last day of the Performance Period, and (ii) achieving the Relative Total Stockholder Return Percentile and Company Absolute Total Stockholder Return performance goals set forth below:

Relative Total Stockholder Return Percentile	**Target Grant Vesting Percentage**
Below 25th Percentile of Peer Group	0% of Target
Between 25th Percentile of Peer Group and up to but less than 75th Percentile	Straight line interpolation between 50% and 150% of Target
At or above 75th Percentile of Peer Group	200% of Target

Company Absolute Total Stockholder Return Percentage	**Absolute TSR Modifier**
Below 0%	75%
Between 0% to 15%	100%

Above 15%	125%

By your signature and the signature of the Company's representative below, you and the Company agree to be bound by all of the terms and conditions of the Restricted Stock Unit Award Agreement attached hereto as *Annex I*, and the Plan (both incorporated herein by this reference as if set forth in full in this document). By executing this Certificate, you hereby irrevocably elect to accept the Restricted Stock Unit rights granted pursuant to this Certificate and the related Restricted Stock Unit Award Agreement and to receive the Restricted Stock Units designated above subject to the terms of the Plan, this Certificate, and the Restricted Stock Unit Award Agreement.

PARTICIPANT	**DIAMONDBACK ENERGY, INC.**
	By:
[Name]	Travis D. Stice, Chief Executive Officer
Dated: _______, 2020	Dated: _______, 2020

ADDENDUM

Definition of "Relative Total Stockholder Return Percentile"

For purposes of this Performance Award, "**Relative Total Stockholder Return Percentile**" means for the Performance Period, the compound annual growth rate amount determined for the Common Stock of the Company equal to the growth in capital from purchasing a share in the Company assuming that the dividends are reinvested each time they are paid (the net stock price change plus the dividends paid during that period = "**Total Stockholder Return**") in comparison to the Total Stockholder Return for each of the companies comprising the Company's Peer Group designated by the Compensation Committee as defined below. How the Company's Total Stockholder Return ranks by percentile relative to the Total Stockholder Return of the other Peer Group companies determines whether the Restricted Stock Unit Target Award vests and how many shares of Common Stock are paid out.

The Company's percentile ranking among the Peer Group Total Stockholder Return is calculated by ranking the Company's Total Stockholder Return as part of the Total Stockholder Return for the Peer Group as a whole. Total Stockholder Return for each member of the Peer Group, including the Company, is determined over a particular measurement period by: dividing (1) the sum of (a) the cumulative value of dividends received during the measurement period, assuming reinvestment, plus (b) the difference between the average share price for the five trading days ending with the last day of the Performance Period compared to the average share price for the five trading days ending immediately prior to the beginning of the Performance Period; by (2) the average share price for the five trading days ending immediately prior to the beginning of the Performance Period. For this purpose, we assume dividends are reinvested in stock at market prices at approximately the same time actual dividends are paid. Shareholder return is quoted on an annualized basis. This is expressed as a compound annual growth rate percentage calculated as TSR = (Pe – Pb + Dividends)/Pb where:

Pb = average share price for the five trading days ending immediately prior to the beginning of the Performance Period;

Pe = average share price for the five trading days ending with the last day of the Performance Period,

Dividends = dividends paid over the Performance Period; and

TSR = Total Shareholder Return.

The Company's Peer Group consists of the following members:

Apache Corporation; Cimarex Energy Co.; Concho Resources Inc.; Continental Resources, Inc.; Devon Energy Corporation; Encana Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Noble Energy, Inc.; Parsley Energy, Inc.; Pioneer Natural Resources Company; WPX Energy, Inc.

Definition of "Absolute TSR Modifier"

For purposes of this Performance Award, "Absolute TSR Modifier" means the percentage determined for the Performance Period as specified in the schedule set forth above based on the Company's annualized Absolute Total Shareholder Return (as defined above in the definition of "Relative Total Stockholder Return Percentile") for the Performance Period.

DIAMONDBACK ENERGY, INC.
2019 AMENDED AND RESTATED EQUITY INCENTIVE PLAN
RESTRICTED STOCK UNIT AWARD AGREEMENT

This Restricted Stock Unit Award Agreement (this "***Agreement***"), is made and entered into on the execution date of the Restricted Stock Unit Award Certificate to which it is attached (the ***"Certificate"***), by and between Diamondback Energy, Inc., a Delaware corporation (the ***"Company"***), and the **Participant** named in the Certificate.

Pursuant to the Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan (the ***"Plan"***), the Administrator has authorized the grant to Participant of the number of Restricted Stock Units set forth in the Certificate (the "***Award***"), upon the terms and subject to the conditions set forth in this Agreement and in the Plan. Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Plan.

NOW, **THEREFORE**, in consideration of the premises and the benefits to be derived from the mutual observance of the covenants and promises contained herein and other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

1. Basis for Award. This Award is made pursuant to Section 7.1 of the Plan for valid consideration provided to the Company by Participant. By Participant's execution of the Certificate, Participant agrees to accept the Award rights granted pursuant to the Certificate and this Agreement, and to receive the Restricted Stock Units designated in the Certificate subject to the terms of the Plan, the Certificate, and this Agreement.

2. Restricted Stock Units Awarded.

2.1 The Company hereby grants to Participant the number of Restricted Stock Units set forth in the Certificate. Each Restricted Stock Unit represents a right to receive one share of Common Stock from the Company payable in accordance with Section 5 below and any Dividend Equivalents (as defined below) credited to the Participant's Restricted Stock Unit Account (as defined below) with respect to that share.

2.2 The Company will, in accordance with the Plan, establish and maintain an account (the "***Restricted Stock Unit Account***") for Participant, and will credit such account for the number of Restricted Stock Units granted to Participant and any Dividend Equivalents as provided in Section 4 below. On any given date, the value of each Restricted Stock Unit will equal the Fair Market Value on such date of one share of Common Stock.

3. Vesting.

3.1 The Restricted Stock Units will vest based on the Target Grant Vesting Percentage as adjusted by the Absolute TSR Modifier, in each case, as determined under the Performance Vesting Goals and Schedules set forth in the Certificate. Except as otherwise provided in an employment agreement, severance plan participation agreement or other service agreement between the Participant and the Company or an Affiliate (a "***Service Agreement***") or as provided in Sections 3.2, 3.3 or 3.4 below, if Participant ceases Continuous Service for any reason prior to the end of the Performance Period, Participant will immediately forfeit all the unvested Restricted Stock Units and any securities, other property or amounts nominally credited to the Restricted Stock Unit Account, including any Dividend Equivalents credited to the Restricted Stock Unit Account that have not been settled or paid.

3.2 Except as otherwise provided in a Service Agreement, in the event of Participant's involuntary termination of employment (other than for Cause, or on account of death or Disability) or resignation for Good Reason, in either case, in connection with the consummation of or within 24 months after the occurrence of a Change in Control (as defined in the Plan), (an "***Acceleration Event***"), with respect to any Restricted Stock Units then outstanding under this Award, the Relative Total Stockholder Return Percentile and Absolute TSR Modifier used to determine the number of Restricted Stock Units that will become vested on the Acceleration Event will be determined based on a Performance Period that ends on the last trading day of the month preceding the date the Change in Control is consummated (the "***Accelerated Performance Period***"). The Total Stockholder Return of the Peer Group will be measured based on the reported closing stock price on the principal exchange on the last day of the Accelerated Performance Period, and the Total Stockholder Return of the Company will be measured on the last day of the Accelerated Performance Period based on the price per share payable to stockholders of the Company in connection with the Acceleration Event. The number of shares determined based on the Relative Total Stockholder Return Percentile for the Accelerated Performance Period, as adjusted by the Absolute TSR Modifier, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will vest immediately and will be settled and paid upon the consummation of such Acceleration Event.

3.3 In the event of the Participant's death or Disability during a period of Continuous Service, the deceased or Disabled Participant's Target Grant Vesting Percentage will be determined at the end of the Performance Period and the deceased or Disabled Participant's Restricted Stock Units, including any unpaid Dividend Equivalents credited to the Restricted Stock Unit Account, will be settled and paid at the same Payment/Settlement Date as if the Participant remained in Continuous Service through the end of the Performance Period.

3.4 To the extent that a Service Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service that is more favorable to Participant than the provisions of this Agreement, such provisions are incorporated by reference in this Agreement.

3.5 For purposes of this Agreement, "***Good Reason***" means Participant's resignation in the event of any (a) material reduction in Participant's base salary, bonus opportunity or severance benefits; (b) relocation of Participant's principal office more than 25 miles from the current location, or (c) material diminution in the Participant's position, duties, reporting relationship or authority, which in any case is not cured within thirty (30) business days after written notice thereof by you to the Board (which notice must be provided by you to the Company within 90 days following the initial occurrence of such event) and an opportunity to cure within the notice period (the "***Cure Period***"). Resignation by the Participant following the Employer's cure or before the expiration of the Cure Period will constitute a voluntary resignation and not a termination or resignation for Good Reason and will not entitle the Participant to any benefits under this Plan. Any termination on account of a Good Reason Resignation must occur within 120 days following the initial occurrence of such event.

4. Dividend Equivalents. If the Company pays any cash dividend on its outstanding Common Stock for which the record date occurs after the Date of Grant, the Administrator will credit the Restricted Stock Unit Account as of the dividend payment date in an amount equal to the amount of the dividend paid by the Company on a single Share multiplied by the number of Restricted Stock Units under this Agreement that are unvested (based on the Target Number of Restricted Stock Units Granted) as of that record date and such number of Restricted Stock Units that are vested but have not been settled under the payment terms of Section 5 ("***Dividend Equivalents***"). Except as otherwise provided in Section 3, Dividend Equivalents will vest and be paid to the Participant on the dividend payment date if Participant is in Continuous Service on the dividend payment date declared by the Company.

5. Payment/Settlement. Subject to Participant's satisfaction of the applicable withholding requirements pursuant to Section 7 hereof, the Company will settle the Award on the Payment/Settlement Date or Dates set forth in the Certificate by issuing to Participant one share of Common Stock for each Restricted Stock Unit payable on that Payment/Settlement Date (and upon such settlement, the Restricted Stock Units will cease to be credited to the Restricted Stock Unit Account). If the Certificate does not specify a Payment/Settlement Date, the applicable Payment/Settlement Date will be the date within 10 business days after the Compensation Committee of the Board has made the certification required under Plan Section 7.2(d) with respect to the performance goals applicable to such Restricted Stock Units following the date of publication of the Corporation's quarterly earnings statement for the twelfth (12th) full quarter following the commencement of the Performance Period (which in any event will be no later than March 15 of the calendar year following the date such performance goals are achieved). If an Acceleration Event occurs, the Payment/Settlement Date will be the date the Acceleration Event occurs. The Administrator will enter Participant's name as a stockholder of record with respect to such shares of Common Stock on the books of the Company with respect to the shares of Common Stock issued on that Payment/Settlement Date free of all restrictions hereunder, except for applicable federal and state securities law restrictions. Participant acknowledges and agrees that shares of Common Stock may be issued in electronic form as a book entry with the Company's transfer agent and that no physical certificates need be issued. Any securities, other property or amounts nominally credited to the Restricted Stock Unit Account other than Restricted Stock Units will be paid in kind or, in the Administrator's discretion, in cash. Except as otherwise provided in Section 3, Dividend Equivalents will vest and be paid to the Participant on the dividend payment date if Participant is in Continuous Service on the dividend payment date declared by the Company. To the extent that a Service Agreement provides for acceleration of vesting of any or all unvested Restricted Stock Units on termination of Continuous Service, such provisions are incorporated by reference in this Agreement.

6. Compliance with Laws and Regulations. The issuance and transfer of shares of Common Stock on any Payment/Settlement Date will be subject to the Company's and Participant's full compliance, to the satisfaction of the Company and its counsel, with all applicable requirements of federal, state, and foreign securities laws and with all applicable requirements of any securities exchange on which the Common Stock may be listed at the time of such issuance or transfer. Participant understands that the Company is under no obligation to register or qualify the shares of Common Stock with the U.S. Securities and Exchange Commission ("***SEC***"), any state securities commission, foreign securities regulatory authority, or any securities exchange to effect such compliance.

7. Tax Withholding.

7.1 As a condition to payment under Section 5 hereof, Participant agrees that on or before the date as of which any portion of the Restricted Stock Units vest, Participant will pay to the Company any federal, state, or local taxes required by law to be withheld with respect to the Restricted Stock Units for which the restrictions lapse and any related securities, other property or amounts then nominally credited to the Restricted Stock Unit Account.

7.2 Participant will pay the amounts due under this Section 7 to the Company. Such amounts will be paid by Stock Withholding, or may be paid at Participant's election, in cash, or (to the extent any applicable insider trading policy, window or restriction does not prohibit Participant from engaging in a sale transaction) by tendering shares of Common Stock held by Participant to a broker selected by the Company for immediate sale and remittance of proceeds equal to the required withholding amount to the Company, including shares that otherwise would be issued and transferred to Participant as payment on the applicable Payment/Settlement Date, with a Fair Market Value on that Payment/Settlement Date that does not exceed the maximum statutory tax rates in the applicable jurisdictions (subject to Participant's written request to withhold more than the required regular tax withholding in the applicable jurisdictions), or a combination of cash and shares of Common Stock. If Participant fails to make such payments, the Company or its Affiliates will, to the extent permitted by law, have the right to deduct from any payment of any kind otherwise due to Participant any federal, state, or local taxes required by law to be withheld with respect to such payment. Dividend Equivalents credited to the Restricted Stock Unit Account will be subject to withholding at the time of payment.

8. Not Transferrable. Until the applicable Payment/Settlement Date, the Restricted Stock Units, any related Dividend Equivalents credited to the Restricted Stock Unit Account and any related securities, other property or amounts nominally credited to the Restricted Stock Unit Account may not be sold, transferred, or otherwise disposed of, and may not be pledged or otherwise hypothecated other than by will or by the applicable laws of descent and distribution, provided that the Restricted Stock Units and any related Dividend Equivalents credited to the Restricted Stock Unit Account will remain subject to the terms of the Plan, the Certificate and this Agreement.

9. No Right to Continued Service. Nothing in this Agreement or in the Plan imposes or may be deemed to impose, by implication or otherwise, any limitation on any right of the Company or any Affiliate to terminate Participant's Continuous Service at any time.

10. Participant's Representations and Warranties. Participant represents and warrants to the Company that Participant has received a copy of the Plan, has read and understands the terms of the Plan, the Certificate, and this Agreement, and agrees to be bound by their terms and conditions. Participant acknowledges that there may be tax consequences upon the payment of the Restricted Stock Units, payment of any Dividend Equivalents credited to the Restricted Stock Unit Account or disposition of any shares of Common Stock received on a Payment/Settlement Date, and that Participant should consult a tax advisor before such time. Participant agrees to sign such additional documentation as the Company may reasonably require from time to time. Participant acknowledges that he or she is aware that copies of the Plan document and the Company's financial statements and information heretofore filed by the Company with the Securities and Exchange Commission (the "***SEC***") are available upon request to the Company, at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549, or by visiting the SEC Internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC.

11. No Interest in Company Assets. All amounts nominally credited to Participant's Restricted Stock Unit Account under this Agreement will continue for all purposes to be part of the general assets of the Company. Participant's interest in the Restricted Stock Unit Account will make Participant only a general, unsecured creditor of the Company.

12. No Stockholder Rights before Delivery. Participant will not have any right, title, or interest in, or be entitled to vote or to receive distributions in respect of, or otherwise be considered the owner of, any of the shares of Common Stock covered by the Restricted Stock Units until the Payment/Settlement Dates specified in the Certificate at which such shares of Common Stock are issued pursuant to Section 5 hereof.

13. Modification. The Agreement may not be amended or otherwise modified except in writing signed by both parties.

14. Interpretation. Any dispute regarding the interpretation of this Agreement must be submitted by Participant or the Company to the Administrator for review. The resolution of such a dispute by the Administrator will be final and binding on the Company and Participant.

15. Entire Agreement. The Plan and the Certificate are incorporated herein by reference. This Agreement, the Certificate, and the Plan constitute the entire agreement of the parties and supersede all prior undertakings and agreements with respect to the subject matter hereof. If any inconsistency or conflict exists between the terms and conditions of this Agreement, the Certificate, and the Plan, the Plan will govern.

16. Successors and Assigns. The Company may assign any of its rights under this Agreement. This Agreement will bind and inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth herein, this Agreement is binding upon Participant and Participant's heirs, executors, administrators, legal representatives, successors, and assigns.

17. Governing Law. This Agreement will be governed by and construed in accordance with the laws of the State of Delaware without giving effect to its conflict of law principles. If any provision of this Agreement is determined by a court of law to be illegal or unenforceable, then such provision will be enforced to the maximum extent possible and the other provisions will remain fully effective and enforceable.

EXHIBIT A

Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan

DIAMONDBACK ENERGY, INC.

SENIOR MANAGEMENT SEVERANCE PLAN

Effective as of February 20, 2020

Table of Contents

DIAMONDBACK ENERGY, INC.
SENIOR MANAGEMENT SEVERANCE PLAN

Effective as of February 20, 2020

Diamondback Energy, Inc., a Delaware corporation ("***Company***"), pursuant to the authorization of the Compensation Committee of the Board, hereby adopts this Diamondback Energy, Inc. Senior Management Severance Plan (the "***Plan***") to provide certain severance pay benefits to Eligible Senior Executives who experience an Eligible Termination, in each case, under the terms and conditions provided herein.

ARTICLE 1
PURPOSE AND SCOPE

Section 1.1 Introduction. The Plan is being adopted pursuant to the authorization of the Compensation Committee of the Board for the benefit of certain Eligible Senior Executives of the Company or any other adopting Employer.

Section 1.2 Purpose. The purpose of the Plan is to provide severance pay benefits under the terms and conditions specified in Article 2 and Article 3 to Eligible Senior Executives who are subject to an Eligible Termination. The severance pay benefits provided hereunder are not required by law and nothing herein creates an obligation to pay severance pay benefits of any kind or amount, except as provided by this Plan. No other employee of the Company, an Affiliate, an Employer or any other Person shall have any rights to benefits under this Plan.

Section 1.3 Plan Status. For tax purposes and for purposes of Title I of ERISA, this Plan document is intended to be governed by ERISA as both an unfunded "employee welfare benefit plan" within the meaning of Section 3(l) of ERISA and a "pension plan" within the meaning of Section 3(2) of ERISA that is an unfunded plan maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees, and shall be interpreted accordingly. This document is intended to serve as both the plan document and, together with the additional information in Appendix A, the summary plan description for the Plan.

ARTICLE 2
ELIGIBILITY FOR SEVERANCE BENEFITS

Section 2.1 Payments and Benefits upon an Eligible Termination (Unrelated to a Change in Control). Subject to the further provisions of this Article 2 and the Participant's continued compliance with his or her obligations under Article 3 hereof, upon a Participant's Eligible Termination (other than on account of death or Disability) that does not occur within the Protection Period:

(a) Accrued Obligations. The Employer will pay or provide to the Participant, the Participant's Accrued Obligations, including any payments required by applicable law;

(b) Prior Year Unpaid Bonus Payment Amount. The Employer will pay an amount, if any, equal to the bonus that would be payable for services attributable to a completed prior year performance period that, as of the Termination Date, has not been paid under the terms of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan, or any successor thereto. The prior year bonus payment amount will be paid after, and only to the extent, it is certified by the Compensation Committee of the Board, and will be paid at the same time bonuses to similarly situated executives are paid, as if the terminated Participant continued to be employed on the certification and bonus payment dates;

(c) Base Salary Continuation. For each month during the period following the Termination Date that applies to the Participant as specified in Schedule A, the Employer will continue to pay to the Participant an amount equal to the product of (i) his or her monthly base salary, as in effect immediately prior to the Eligible Termination (or immediately prior to any event constituting Good Reason, if applicable), multiplied by (ii) the multiple specified in Schedule A that is applicable to such Participant. The Base Salary Continuation amount will be payable in substantially equal periodic installments commencing on the Payment Date in accordance with the normal payroll practices of the Employer;

(d) Pro-rated Target Annual Bonus. To the extent not paid or payable under the terms of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan, or any successor thereto, Employer will pay to the Participant a lump sum amount in cash equal to the Participant's target annual bonus for the year that includes the Termination Date pro-rated to reflect the number of days that the Participant was employed by an Employer or an Affiliate during such calendar year. Such pro-rated target annual bonus amount will be payable on the Payment Date;

(e) Group Health Plan Premiums. Provided that the Participant timely and properly elects and continues to be eligible for group health plan continuation coverage under COBRA for himself and/or his eligible dependents under an adopting Employer's or an Affiliate's group health plans, the Employer will reimburse the Participant on a monthly basis for the premium cost of such COBRA continuation coverage during the Continuation Period. Subject to the Participant submitting adequate substantiation of payment of the applicable COBRA premiums, the reimbursements will commence on the Payment Date and continue on a monthly basis for the remainder of the Continuation Period, but not more than 18 months following the commencement thereof;

(f) Equity Awards. Except as otherwise set forth in a Participation Agreement between the Company and a Participant, each outstanding unvested equity-based compensation award granted by the Company or an Affiliate that is held by or for the Participant will be forfeited or vested, as applicable, in accordance with the applicable equity award agreement. Any vested awards will be settled, based on the vesting, forfeiture and settlement terms of the applicable equity award agreements.

Section 2.2 Severance Benefits upon an Eligible Termination (Related to a Change in Control). Subject to the further provisions of this Article 2, upon a Participant's Qualifying Termination (other than on account of death or Disability) that occurs within the Protection Period, the Participant will receive all of the payments and benefits described in Section 2.1 above, except that the following substitution and modification will be made:

(a) Lump Sum Compensation Payment. In lieu of any Base Salary Continuation payment under Section 2.1(c), the Employer will pay to the Participant an amount in cash equal to the product of:

(i) the sum of (A) the Participant's annualized base salary as in effect immediately prior to the Eligible Termination (or immediately prior to any event constituting Good Reason, if applicable), plus (B) the Average Annual Bonus amount in effect immediately preceding the Termination Date; multiplied by

(ii) the Applicable Factor specified in Schedule B that applies to the Participant.

(b) Payment Timing. The lump sum compensation payment amount determined in Section 2.2(a) will be paid in a single lump sum on the Payment Date.

Section 2.3 Payments upon a Termination of Employment Due to Death or Disability. Subject to the further provisions of this Article 2, upon a Participant's Eligible Termination due to death or Disability:

(a) Accrued Obligations. The Employer will pay or provide to the Participant or his or her Personal representative or estate, the Participant's Accrued Obligations.

(b) Prior Year Unpaid Bonus Payment Amount. The Employer will pay to the Participant or his or her Personal representative or estate an amount, if any, equal to the bonus that would be payable for services attributable to a completed prior year performance period that, as of the Termination Date, has not been paid under the terms of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan, or any successor thereto. The prior year bonus payment amount will be paid after, and only to the extent, it is certified by the Compensation Committee of the Board, and will be paid at the same time bonuses to similarly situated executives are paid, as if the terminated Participant continued to be employed on the certification and bonus payment dates;

(c) Base Salary Continuation. For each month during the period following the Termination Date that applies to the Participant as specified in Schedule A, the Employer will continue to pay to the Participant or his or her Personal representative or estate an amount equal to the product of (i) his or her monthly base salary, as in effect immediately prior to the Eligible Termination (or immediately prior to any event constituting Good Reason, if applicable), multiplied by (ii) the multiple specified in Schedule A that is applicable to such Participant. The Base Salary Continuation amount will be payable in substantially equal periodic installments commencing on the Payment Date in accordance with the normal payroll practices of the Employer;

(d) Pro-rated Target Annual Bonus. To the extent not paid or payable under the terms of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan, or any successor thereto, Employer will pay to the Participant or his or her Personal representative or estate a lump sum amount in cash equal to the Participant's target annual bonus for the year that includes the Termination Date pro-rated to reflect the number of days that the Participant was employed by an Employer or an Affiliate during such calendar year. Such pro-rated target annual bonus amount will be payable on the Payment Date;

(e) Equity Awards. Except as otherwise set forth in a Participation Agreement between the Company and a Participant, each outstanding unvested equity-based compensation award granted by the Company or an Affiliate that is held by or for the Participant will be forfeited or vested, as applicable, in accordance with the terms of the applicable equity award agreements. Any vested awards will be settled, based on the vesting, forfeiture and settlement terms of the applicable equity award agreements.

Section 2.4 Release and Full Settlement; Payment Delay; Repayment Obligations.

(a) Release and Full Settlement. Any provision of this Plan to the contrary notwithstanding, the payment of any amounts or provision of any benefits under Section 2.1, Section 2.2, Section 2.3 or Section 3.2 will be subject to the Participant's (or, if applicable, his Personal representative or estate's) execution, within forty five (45) days following receipt (or such shorter period as set forth in such release), of a waiver and general release of claims in the form provided by the Administrator, and such waiver and general release of claims becoming effective and irrevocable in accordance with its terms within sixty (60) days following the Termination Date.

(b) Payment Timing. Except as set forth in the following sentence, any payments pursuant to Section 2.1, Section 2.2, Section 2.3 or Section 3.2 that would otherwise be payable in the first sixty (60) days following the Termination Date will be withheld and any unpaid installments will become payable in a lump sum on the date that is sixty (60) days following the Termination Date. However, if the Participant is a Specified Employee, any payments hereunder that constitute a "deferral of compensation" within the meaning of Section 409A and to which the Participant would otherwise be entitled during the first six months following the Termination Date will be accumulated and paid to the Participant on the date that is six months following the Termination Date (or if earlier, to the Participant's estate or Personal representative upon the Participant's death).

(c) Clawback or Forfeiture of Payments. The payment of any amounts or provision of any benefits under Section 2.1, Section 2.2, Section 2.3 or Section 3.2 hereof will be subject to the Participant's continued compliance with his or her Restrictive Covenant obligations under Article 3, and, in the event of any breach of such obligations by the Participant, the Participant agrees to promptly repay the Employer the gross amount or value of any payments or benefits provided under this Article 2. Notwithstanding any provision in this Plan or any Participation Agreement to the contrary, if Participant breaches the

Restrictive Covenant Provisions of Article 3, or if required by any policy of the Company, the Employer or an Affiliate, by the Dodd-Frank Wall Street Reform and Consumer Protection Act or the Sarbanes–Oxley Act of 2002 or by other applicable law in effect as of the time that any benefit payment is paid hereunder, each Participant's benefits under this Plan shall be conditioned on repayment or forfeiture in accordance with such applicable laws, policy, or any relevant provision of the related Participation Agreement. By entering into a Participation Agreement and becoming a Participant under this Plan, a Participant will have consented to any such clawback, repayment or forfeiture condition, regardless of whether or not such condition is expressly stated in the Participation Agreement.

Section 2.5 Parachute Payments. Notwithstanding any other provisions of this Plan, in the event that any payment or benefit received or to be received by a Participant (including any payment or benefit received in connection with a Change in Control or the termination of a Participant's employment during the Protected Period, whether pursuant to the terms of this Plan or any other plan, arrangement or agreement) (all such payments and benefits, including the payments and benefits under this Plan, being hereinafter referred to as the "**Total Payments**") would be subject (in whole or part), to the excise tax imposed under Section 4999 of the Code (the "**Excise Tax**"), then, after taking into account any reduction in the Total Payments provided by reason of Section 280G of the Code in such other plan, arrangement or agreement, the Total Payments shall be reduced, in the order set forth below, to the extent necessary so that no portion of the Total Payments is subject to the Excise Tax, but only if (x) the net amount of such Total Payments, as so reduced (and after subtracting the net amount of federal, state and local income taxes on such reduced Total Payments and after taking into account the phase out of itemized deductions and Personal exemptions attributable to such reduced Total Payments) is greater than or equal to (y) the net amount of such Total Payments without such reduction (but after subtracting the net amount of federal, state and local income taxes on such Total Payments and the amount of Excise Tax to which the Participant would be subject in respect of such unreduced Total Payments and after taking into account the phase out of itemized deductions and Personal exemptions attributable to such unreduced Total Payments).

(a) Total Payments Reduction. The Total Payments shall be reduced by the Administrator in its reasonable discretion in the following order: (A) reduction of any cash severance payments otherwise payable that are exempt from Section 409A of the Code; (B) reduction of any other cash payments or benefits otherwise payable that are exempt from Section 409A of the Code, but excluding any payments attributable to the acceleration of vesting or payments with respect to any stock option or other equity award with respect to Company's or an Affiliate's common stock or other form of equity award that are exempt from Section 409A of the Code; (C) reduction of any other payments or benefits otherwise payable to you on a pro-rata basis or such other manner that complies with Section 409A of the Code, but excluding any payments attributable to the acceleration of vesting and payments with respect to any stock option or other equity award with respect to Company's or an Affiliate's common stock or other form of equity award that are exempt from Section 409A of the Code; and (D) reduction of any payments attributable to the acceleration of vesting or payments with respect to any stock option or other equity award with respect to Company's or an Affiliate's common stock or other equity interest that are exempt from Section 409A of the Code; provided, however, that no reduction of a payment or benefit of nonqualified deferred compensation that is subject to Section 409A of the Code shall be made to the extent that such reduction would result in any other payment or benefit being deemed a substitute (within the meaning of Section 1.409A-3(f) of the Treasury Regulations) for the forfeited amount by reason of such other payment or benefit having a different time or form of payment.

(b) Performance of Calculations. For purposes of determining whether and the extent to which the Total Payments will be subject to the Excise Tax, (A) no portion of the Total Payments the receipt or enjoyment of which a Participant has waived at such time and in such manner as not to constitute a "payment" within the meaning of Section 280G(b) of the Code shall be taken into account; (B) no portion of the Total Payments shall be taken into account which, in the written opinion of independent accountants of nationally recognized standing ("**Accounting Firm**") selected by Company, does not constitute a "parachute payment" within the meaning of Section 280G(b)(2) of the Code (including by reason of Section 280G(b)(4)(A) of the Code) and, in calculating the Excise Tax, no portion of such Total Payments shall be taken into account which, in the opinion of Accounting Firm, constitutes reasonable compensation for services actually rendered, within the meaning of Section 280G(b)(4)(B) of the Code, in excess of the Base Amount (as defined in Section 280G(b)(3) of the Code) allocable to such reasonable compensation; and (C) the value of any non-cash benefit or any deferred payment or benefit included in the Total Payments shall be determined by the Accounting Firm in accordance with the principles of Sections 280G(d)(3) and (4) of the Code.

(c) Cooperation. If applicable, Participant, Company and Affiliates will each provide the Accounting Firm access to and copies of any books, records and documents in their respective possession, reasonably requested by the Accounting Firm, and otherwise cooperate with the Accounting Firm in connection with the preparation and issuance of the determinations and calculations contemplated by this Section 2.5. The fees and expenses of the Accounting Firm for its services in connection with the determinations and calculations contemplated by this Section 2.5 will be borne by Company.

(d) No Gross-Ups. None of the Company, any Affiliate or any Employer is obligated to provide a gross-up or similar payment to any Participant who is subject to Excise Tax on the Total Payments.

Section 2.6 Coordination with Certain Other Agreements. The benefits under, and participation in, this Plan are intended to supersede and replace the severance and separation benefits to which an Participant may be entitled under any other plan, policy, agreement or arrangement. By executing a Participation Agreement with the Company to participate in this Plan, an Eligible Senior Executive will waive any right to severance or separation benefits under any other severance or separation benefits plan, policy, agreement or arrangement of any Employer.

Section 2.7 No Mitigation. A Participant will not be required to mitigate the amount of any payment or benefit provided for in this Article 2 or Section 3.2 by seeking other employment or otherwise, nor will the amount of any payment or benefit provided for in this Article 2 or Section 3.2 be reduced by any compensation or benefit earned by the Participant as the result of employment by another employer.

Section 2.8 Deductions from Severance Benefits. The following items will be deducted from the benefits paid under the Plan:

(a) All Federal, State and local taxes that the Administrator determines the Plan must or may deduct or withhold;

(b) To the extent permitted by law, any amounts a Participant owes to the Company, any Affiliate or any Employer; and

(c) Any amount of garnished earnings which are required to be withheld from the Participant's pay, if Employer has been garnishing the Participant's earnings pursuant to an order of garnishment, child support or tax lien.

ARTICLE 3
RESTRICTIVE COVENANTS

Section 3.1 Non-Competition and Non-Solicitation Obligations. In consideration of the payments and benefits that may be paid or provided to the Participant hereunder and to protect the trade secrets and confidential information of the Company and its Affiliates that have been and will in the future be disclosed or entrusted to the Participant, the business goodwill of the Company or its Affiliates, and the business opportunities that have been and will in the future be disclosed or entrusted to the Participant by the Company or its Affiliates, the Company and the Participant agree to the provisions of this Article 3. The Participant agrees that during the Restricted Period, the Participant will not:

(a) Non-Competition. Without the written consent of the Compensation Committee of the Board, at any time or in any manner, either directly or indirectly, become associated with, render services to, invest in, represent, advise or otherwise participate as an officer, employee, director, stockholder, partner, member, agent of or consultant for any company, business, organization or other legal or natural person that engages or participates in the Restricted Business; provided, however, that nothing herein shall prevent a Participant from acquiring up to two percent (2%) of the securities of any company listed on a national securities exchange or quoted on the NASDAQ quotation system, provided Participant's involvement with any such company is solely that of a passive stockholder. The covenant contained in this Section 3.1(a) shall be deemed a series of separate covenants for each state, county and city in which the Diamondback Parties' business is conducted or is preparing to be conducted. If, in any judicial proceeding, a court shall refuse to enforce all of the separate covenants deemed included in this Section 3.1(a) because, taken together, they cover too extensive a geographic area, the parties intend that those covenants (taken in order of the states, counties and cities therein which are least populous), which if eliminated would permit the remaining separate covenants to be enforced in such proceeding, shall, for the purpose of such proceeding, be deemed eliminated from the provisions of this Section 3.1(a).

(b) Non Solicitation, Non Hire of Employees. At any time or in any manner, either directly or indirectly, either on Participant's behalf or on behalf of any Person (other than the Diamondback Parties), recruit, solicit, hire, divert or otherwise encourage or attempt to recruit, solicit, hire, divert or otherwise encourage any officer or employees or agents of any Diamondback Party to enter into any employment, consulting or advisory arrangement or contract with or to perform any services for or on Participant's behalf or on behalf of any Person (other than a Diamondback Party), or to enter into any kind of business with Participant or any other Person, including, without limitation, any Restricted Business.

(c) Non-Interference. At any time or in any manner, either directly or indirectly, for the Participant's own account or for the account of any other Person, interfere with any Diamondback Party's relationship with any of its land owners, mineral owners, gatherers, processors, employees, contractors, suppliers or regulators or any other third party with which a Diamondback Party maintains a business relationship.

Section 3.2 Limitations on Non-Competition. Notwithstanding the provisions of Section 3.1, if the Participant provides written notice to the Employer that the Participant will terminate employment with the Employer pursuant to a resignation by the Participant that does not constitute an Eligible Termination, then, solely for purposes of Section 3.1(a), the Restricted Period will end on a date selected by the Company and set forth in a written notice provided by the Company to the Participant; provided, however, that (a) the date selected by the Company will be a whole number of months (not in excess of 12) after the Termination Date and (b) subject to the provisions of Section 2.4 hereof, beginning on the Payment Date, the Employer will pay to the Participant an amount equal to one-twelfth of the Participant's annualized base salary plus target annual bonus for each month of the Restricted Period, which amount will be paid on a prorated basis on each regularly scheduled payroll date during the Restricted Period following the Termination Date. The Participant hereby delegates to the Company the right to select and determine in good faith the duration of the Restricted Period as provided in this Section 3.2.

Section 3.3 Non-Disparagement. During and following the Participant's employment with the Employer, the Participant agrees not to make public statements, negative comments or otherwise disparage any Diamondback Party or any Diamondback Party's officers, directors, employees, agents, shareholders or other equity holders in any manner harmful to them or their business, business reputation or personal reputation. The foregoing shall not be violated by truthful statements in response to legal process, required governmental testimony or filings, or administrative or arbitral proceedings (including, without limitation, depositions in connection with such proceedings).

Section 3.4 Return of Property. All materials, records and documents in any medium made by a Participant or coming into a Participant's possession during employment concerning any products, processes or services, manufactured, used, developed, investigated, provided or considered by any Diamondback Party or otherwise concerning the business or affairs of the Diamondback Parties, are the sole property of the applicable Diamondback Party, and upon termination of a Participant's employment, or upon request of the Company during employment, a Participant will promptly deliver the same to the Diamondback Party designated by the Company. In addition, upon termination of employment, or upon request of the Company during a Participant's employment, the Participant will deliver to the Diamondback Party designated by the Company all other property of the Diamondback Parties in Participant's possession or under Participant's control, including, but not limited to, confidential or proprietary data or information, financial statements, marketing and sales data, drawings, documents and electronic records.

Section 3.5 Cooperation. Upon the receipt of reasonable notice from the Company, an Employer or an Affiliate (including outside counsel), a Participant agrees that while employed by any Diamondback Party and thereafter, the Participant will provide reasonable assistance to any Diamondback Party and their respective representatives in defense of any claims that may be made against any Diamondback Party and will assist any Diamondback Party in the prosecution of any claims that may be made by any Diamondback Party, to the extent that such claims relate to the period of participant's employment with a Diamondback Party. Participants agree to promptly inform the Company if they become aware of any lawsuits involving such claims that may be filed or threatened against any Diamondback Party. Participants also agree to promptly inform the Company (to the extent legally permitted to do so) if asked to assist in any investigation of any Diamondback Party (or its actions), regardless of whether a lawsuit or other proceeding has then been filed against any Diamondback Party with respect to such investigation. Upon presentation of appropriate documentation, the Company or an Employer will pay or reimburse the Participant for all reasonable, out-of-pocket expenses incurred in complying with this Section 3.5. If at the time of compliance Participant is no longer an employee, officer or director (or functional equivalent) of any Diamondback Party, the Company or an Employer will provide a reasonable per diem.

Section 3.6 Confidential Information.

(a) Confidentiality. In the course of employment with the Diamondback Parties, a Participant will have had, and/or will have, access to confidential or proprietary data or information of the Diamondback Parties. Each Participant hereby agrees to not at any time during or after employment divulge or communicate to any Person (which term, for purposes of this Plan, includes both individual Persons or entities) nor shall a Participant direct any employee of a Diamondback Party to divulge or communicate to any Person (other than to a Person bound by confidentiality obligations similar to those contained herein and other than as necessary in performing your duties hereunder), or use to the detriment of the Diamondback Parties or for the benefit of any other Person, any of such data or information. No business conducted by a Participant or any organization of which a Participant, directly or indirectly, is an owner, partner, manager, joint venturer, director, officer, manager or otherwise a participant in or connected with in any locality, state or country in which the Diamondback Parties conduct business may use any name, designation or logo which is substantially similar to that presently used by any Diamondback Party. The term "**confidential or proprietary data or information**" as used in this Plan means any information not generally available to the public or generally known within the applicable Diamondback Party's industry, including, without limitation, Personnel information, financial information, customer lists or contacts, vendor lists and pricing information, strategy and plans, engineering data and analysis, maps, samples, well logs, well production information, geological data, geophysical data, seismic data, information regarding operations, systems, services, know-how, computer and any other processed or collated data, trade secrets (including, without limitation, software), computer programs, pricing, marketing and advertising data.

(b) Proprietary Information and Disclosure. Each Participant agrees that they will at all times promptly disclose to the Company, in such form and manner as the Company or an Employer may require, any inventions, improvements or procedural or methodological innovations, program methods, forms, systems, services, designs, marketing ideas, products or processes (whether or not capable of being trademarked, copyrighted or patented) conceived or developed or created by the Participant during or in connection with employment with any Diamondback Party and which relate to the business of any Diamondback Party ("**Intellectual Property**"). Each Participant agrees that all such Intellectual Property constitutes a work-for-hire and will be the sole property of the applicable Diamondback Party. Each Participant further agrees that he or she will execute such instruments and perform such acts as may be requested by the Company or an Employer to transfer to and perfect in the entity designated by the Company all legally protectable rights in such Intellectual Property.

ARTICLE 4
CLAIMS AND APPEAL PROCEDURES

Section 4.1 Filing Claim for Benefits. If a Participant or Beneficiary ("**Claimant**") believes he or she has not received the benefits Claimant is entitled to receive under the terms of the Plan, Claimant may file a claim for benefits with the

Administrator. All claims must be made in writing and must be signed by Claimant or an authorized representative. If Claimant does not furnish sufficient information to determine the validity of the claim, the Administrator will indicate to Claimant any additional information which is required.

Section 4.2 Notification by the Administrator. Each claim will be approved or disapproved by the Administrator within 90 days following the receipt of the information necessary to process the claim (45 days if the claim relates to a Plan determination of disability (a "**Disability Claim**")). In the event the Administrator denies a claim for benefits in whole or in part, the Administrator will notify Claimant in writing or by electronic notification of the denial of the claim. Such notice by the Administrator will also set forth, in a manner calculated to be understood by Claimant, the specific reason for such denial, the specific Plan provisions on which the denial is based, a description of any additional material or information necessary to perfect the claim with an explanation of why such material or information is necessary, and an explanation of the Plan's claim review procedure as set forth in Section 4.3 and the time limits applicable to such procedures, including a statement of Claimant's right to bring a civil action under Section 502 of ERISA following a claim denial after review. These periods may be extended by the Administrator for up to 90 days (30 days in the case of a Disability Claim), if the Administrator determines that such an extension is necessary due to matters beyond the control of the Plan and notifies Claimant, prior to expiration of the initial notification period, of the circumstances requiring an extension of time and the date by which the Administrator expects to render a decision. In the case of a Disability Claim, the Administrator may further extend the period for making a determination by up to an additional 30 days if, prior to the end of the first 30 day extension period, the Administrator determines that such an additional extension is necessary due to matters beyond the control of the Plan and notifies Claimant of the circumstances requiring an extension of time and the date by which the Administrator expects to render a decision. If no action is taken by the Administrator on a claim within 90 days (45 days for a Disability Claim), the claim will be deemed to be denied for purposes of the review procedure, unless the failure was a de minimis violation that does not cause and is not likely to cause prejudice or harm to Claimant and the Administrator demonstrates that the failure was for good cause or due to matters beyond the control of the Administrator and that the failure occurred in the context of an ongoing good faith exchange of information between the Plan and Claimant.

Section 4.3 Review Procedure. A Claimant may appeal a denial of his or her claim by requesting a review of the decision by the Administrator or a Person designated by the Administrator, which Person will be a Named Fiduciary under Section 402(a)(2) of ERISA for purposes of this Section 4.3. An appeal must be submitted in writing within 60 days (180 days in the case of a Disability Claim) after the denial and must:

(a) Request a review of the claim for benefits under the Plan;

(b) Set forth all of the grounds under which Claimant's request for review is based and any facts in support thereof; and

(c) Set forth any issues or comments which Claimant deems pertinent to the appeal.

In connection with an appeal, Claimant and his or her legal representative will be given the opportunity to:

(i) submit written comments, documents, records, and other information relating to the claim for benefits;

(ii) obtain reasonable access, upon request and free of charge, to review and obtain copies of pertinent documents or materials upon submission of a written request to the Administrator or Named Fiduciary, provided the Administrator or Named Fiduciary finds the requested documents or materials are relevant to Claimant's claim for benefits within the meaning of claims procedure regulation 29 C.F.R. § 2560.503-1(m)(8).

On the basis of its review, the Administrator or Named Fiduciary will make an independent determination of Claimant's eligibility for benefits under the Plan. The review will take into account all comments, documents, records, and other information submitted by Claimant relating to the claim for benefits, without regard to whether such information was submitted or considered in the initial benefit claim determination. The Administrator or the Named Fiduciary designated by the Administrator will act upon each appeal within 60 days (45 days in the case of a Disability Claim appeal) after receipt thereof, unless special circumstances require an extension of the time for processing, in which case a decision will be rendered as soon as possible, but not later than 120 days (90 days in the case of a Disability Claim appeal) after the appeal is received. The decision of the Administrator or Named Fiduciary on any claim for benefits will be final and conclusive upon all parties thereto. In the event the Administrator or Named Fiduciary denies an appeal in whole or in part, it will give written or electronic notice of the decision to Claimant within five days of the date the determination is made, which notice will set forth in a manner calculated to be understood by Claimant the specific reasons for such denial and which will make specific reference to the pertinent Plan provisions on which the decision was based. The notice will also contain a statement that Claimant is entitled to receive upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to claimant's claim for benefits, within the meaning of claims procedure regulation 29 C.F.R. § 2560.503-1(m)(8) and a statement of Claimant's right to bring a civil action under Section 502 of ERISA.

(d) Effective for Disability Claims filed on or after the Effective Date, the following additional rules will apply:

(i) Notice to Claimant of any extension of the 45-day period for initial determination must include the circumstances requiring the extension and the date as of which a decision is expected, with a specific explanation of the standards on which entitlement to a disability benefit are based, the unresolved issues preventing a decision on the Disability Claim and the information needed to resolve those issues, and must give Claimant 45 days to provide any information requested.

(ii) In addition to the information provided with respect to other claims, the notification of denial of a Disability Claim must include the following:

(A) A discussion of the decision, including an explanation of the basis for disagreeing with or not following the views presented by Claimant to the Plan of health care professionals who are treating the Participant and vocational professionals who have evaluated the Participant; medical or vocational experts whose advice was obtained on behalf of the Plan in connection with the Disability Claim, without regard to whether the advice was relied on in making the determination; and any disability determination made by the Social Security Administration presented to the Plan by Claimant.

(B) Either the specific internal rules, guidelines, protocols, standards or other similar criteria of the Plan relied on in making the decision, or a statement that such rules, guidelines, protocols, standards or other similar criteria of the Plan do not exist.

(C) A statement that Claimant may request, free of charge, reasonable access to and copies of all documents, records and other information relevant to the Disability Claim.

(iii) Subsequent review of any decision denying a Disability Claim must be conducted by an independent and impartial fiduciary not involved in the initial determination. Claimant shall be notified in writing not later than 45 days after receipt of a request for a review. This 45-day period may be extended for an additional 45 days if special circumstances require the extension. Before the Plan can issue an adverse determination on appeal, Claimant shall be provided, free of charge, with any new or additional evidence considered, relied on or generated by the Plan administrator or other Person making the benefit determination (or at the direction of the Plan administrator or such other Person) in connection with the Disability Claim. Such evidence shall be provided to Claimant as soon as possible and sufficiently before the deadline for the notice of adverse determination, to give Claimant a reasonable opportunity to respond. Before the Plan can issue an adverse determination on appeal based on new or additional rationale, Claimant shall be provided, free of charge, with such rationale. The rationale will be provided as soon as possible and sufficiently before the deadline for the notice of adverse determination to give Claimant a reasonable opportunity to respond.

(iv) In addition to the information provided for all other claims on appeal, the notice of determination of a Disability Claim appeal must include an explanation of the basis for disagreeing with or not following the views presented by Claimant of health care professionals treating the Participant and vocational professionals who evaluated the Participant, the views of medical or vocational experts whose advice was obtained on behalf of the Plan administrator (regardless of whether the advice was relied upon), and any disability determination of the Social Security Administration presented by Claimant to the Plan administrator. The notice also shall include either the specific internal rules, guidelines, protocols, standards or other similar criteria relied on in making the decision or a statement that no such rules, guidelines, protocols, standards or other similar criteria exist, and a statement informing Claimant of his or her right to bring a civil suit under federal law (and a description of the Plan's limitation period for doing so, if any).

Section 4.4 Administrator's Authority. As provided in Section 5.1, the Plan Administrator has the discretionary authority to interpret the Plan, make factual findings and determinations and make final decisions with respect to paying claims under the Plan. All determinations of the Plan administrator shall be final, conclusive and binding on all interested parties, unless the actions of the Plan Administrator are arbitrary and capricious.

ARTICLE 5
PLAN ADMINISTRATION

Section 5.1 In General. The general administration of the Plan and the duty to carry out its provisions shall be vested in the Administrator, which shall be the "plan administrator" as that term is defined in Section 3(16)(A) of ERISA. The Plan and the severance benefits payable under the Plan shall be administered by the Administrator, which will be the Compensation Committee of the Board or its delegate, unless otherwise appointed from time to time by the Board. The Administrator may, in its discretion, secure the services of other parties, including agents and/or employees to carry out the day-to-day functions necessary to an efficient operation of the Plan. The Administrator's interpretations, decisions, requests and exercises of power and responsibilities shall not be subject to review by anyone and shall be final, binding, and conclusive upon all Persons. The Administrator shall, in its sole and absolute discretion, have the exclusive right to interpret all of the terms of the Plan, to determine eligibility for coverage and benefits, to make reasonable and uniform rules and regulations required in the administration of the Plan, to resolve disputes as to eligibility, type, or amount of benefits, to correct any errors or omissions in the form or operation of the Plan, to make such other determinations with respect to the Plan, and to exercise such other powers and responsibilities as shall be provided for in the Plan or as shall be necessary or helpful with respect thereto. The Administrator under and pursuant to this Plan shall be the named fiduciary for purposes of Section 402(a) of ERISA with respect to all powers and duties expressly or implicitly assigned to it hereunder.

Section 5.2 Reimbursement and Compensation. The Administrator shall receive no compensation for its services as Administrator, but it shall be entitled to reimbursement for all sums reasonably and necessarily expended by it in the performance of such duties.

ARTICLE 6
AMENDMENT AND TERMINATION

The Company, by action of the Compensation Committee of its Board, reserves the right to amend or terminate the Plan, without the consent of any Person or entity. However, no such amendment may eliminate the right to receive severance benefits which an Eligible Senior Executive has accrued or become entitled to under Article 2 of the Plan prior to the effective date of such amendments or termination. Such amendment or termination shall be effective when adopted in an instrument in writing, duly executed on behalf of Company. This Plan may not be amended on or following a Change in Control to adversely affect the benefits or rights to benefits (contingent or otherwise) of any Participant under this Plan or terminated on or following a Change in Control until there are no longer any benefits potentially payable under this Plan. Further, a participating Employer may not terminate its participation in this Plan on or following a Change in Control unless and until it no longer employs any Participants and has otherwise satisfied its obligations to pay benefits under this Plan.

ARTICLE 7
CODE SECTION 409A

Section 7.1 Deferred Compensation Exceptions. Payments under this Plan will be administered and interpreted to maximize the short-term deferral exception to and the involuntary separation pay exception under Section 409A of the Code and the regulations thereunder (collectively "***Section 409A***"). The portion of any payment under this Plan that is paid within the short-term deferral period (within the meaning of Code Section 409A and Treas. Regs. §1.409A-1(b)(4)) or that is paid within the involuntary separation pay safe harbor (as described in Code Section 409A and Treas. Regs. §1.409A-1(b)(9)(iii)) will not be treated as nonqualified deferred compensation and will not be aggregated with other nonqualified deferred compensation plans or payments.

Section 7.2 Separate Payments and Payment Timing. Any payment or installment made under this Plan, any amount that is paid as a short-term deferral, within the meaning of Treas. Regs. §1.409A-1(b)(4), and any payment within the involuntary separation pay safe harbor exception in Treas. Regs. §1.409A-1(b)(9)(iii) will be treated as separate payments. Executive will not, directly or indirectly, designate the taxable year of a payment made under this Plan, and if the release period discussed in Section 2.4 above spans two (2) calendar years, payment of any amounts that are subject to Section 409A shall be paid in the later calendar year. Payment dates provided for in this Plan will be deemed to incorporate grace periods that are treated as made upon a designated payment date within the meaning of Code Section 409A and Treas. Regs. §1.409A-3(d). The Company does not guaranty or warrant the tax consequences of this Plan and, except as specifically provided to the contrary in this Plan, each Eligible Senior Executive, in all cases, will be liable for any taxes due as a result of this Plan. Neither the Company nor any of its Affiliates shall have any obligation to indemnify or otherwise hold any Eligible Senior Executive harmless from any or all such taxes, interest or penalties, or liability for any damages related thereto.

Section 7.3 General Section 409A Provisions. If for any reason, the short-term deferral or involuntary separation pay plan exception is inapplicable, payments and benefits payable to any Participant under this Plan are intended to comply with the requirements of Section 409A. To the extent the payments and benefits under this Plan are subject to Section 409A, this Plan will be interpreted, construed and administered in a manner that satisfies the requirements of Sections 409A(a)(2), (3) and (4) of the Code and the Treasury Regulations thereunder (and any applicable transition relief under Section 409A of the Code).

(a) If the Company determines that any payments or benefits payable under this Plan intended to comply with Sections 409A(a)(2), (3) and (4) of the Code do not comply with Section 409A of the Code, the Company may amend this Plan, or take such other actions as the Company deems reasonably necessary or appropriate, to comply with the requirements of Section 409A of the Code, the Treasury Regulations thereunder (and any applicable relief provisions) while preserving the economic agreement of the parties. If any provision of the Plan would cause such payments or benefits to fail to so comply, such provision will not be effective and will be null and void with respect to such payments or benefits, and such provision will otherwise remain in full force and effect.

(b) All payments considered nonqualified deferred compensation under Section 409A and the regulations thereunder will be made on the date(s) provided herein and no request to accelerate or defer any payment under this Section will be considered or approved for any reason whatsoever, except as permitted under Section 409A. Notwithstanding the foregoing, amounts payable hereunder which are not nonqualified deferred compensation, or which may be accelerated pursuant to Section 409A, such as distributions for applicable tax payments, may be accelerated, but not deferred, at the sole discretion of Company.

(c) To the extent required to comply with Section 409A, all references in this Plan to termination of employment or termination mean an Employee's "separation from service" as that term is defined in Section 1.409A-1(h) of the Treasury Regulations.

Section 7.4 Specified Employee Status.

(a) If a Participant is a specified employee (within the meaning of Code Section 409A) on the date of his or her separation from service, any payments made with respect to such separation from service under this Plan, and other payments or benefits under this Plan that are subject to Section 409A of the Code, will be delayed in order to comply with Section 409A(a)(2)(B)(i) of the Code, and such payments or benefits will be paid or distributed to you during the five-day period commencing on the earlier of: (i) the expiration of the six-month period measured from the date of Participant's separation from service, or (ii) the date of Participant's death. Upon the expiration of the applicable six-month period under Section 409A(a)(2)(B)(i) of the Code, all payments deferred pursuant to this Section 7.4 will be paid to Executive (or Executive's estate, in the event of Executive's death) in a lump sum payment. Any remaining payments and benefits due under the Plan will be paid as otherwise provided in the Plan.

(b) To minimize the risk that the six-month delay pursuant to the preceding paragraph will disrupt coverage under any employee benefit plan in which Executive is entitled to participate following the termination of employment, payments that are not considered deferred compensation because they are paid as a short-term deferral or are within the involuntary separation pay safe harbor exception that are made during the six months following the termination of your employment shall first be applied to cover any costs relating to such continued employee benefits plan coverage, but only to the extent that such coverage would constitute deferred compensation for purposes of Section 409A, and thereafter shall be made in respect of other amounts or benefits owed to you.

ARTICLE 8
MISCELLANEOUS INFORMATION

Section 8.1 Other Participating Employers. The Company is the Plan sponsor and Diamondback E&P, LLC is an adopting Employer under this Plan. It is contemplated that other subsidiaries and Affiliates of the Company may adopt this Plan, with the approval of the Compensation Committee of the Board, and thereby become an Employer hereunder. Any such entity, whether or not presently existing, may become an Employer by appropriate action of its board of directors or non-corporate counterpart. The provisions of this Plan will apply separately and equally to each Employer and its employees in the same manner as is expressly provided for the Company and its employees, except that the determination of whether a Change in Control has occurred will be made based solely on the Company. Transfer of employment among the Company and other participating Employers will not be considered an Eligible Termination hereunder unless such transfer otherwise constitutes a Good Reason event. A sale of assets or other transaction where a Participant's employment is transferred to a successor or acquiring entity and there is no loss of employment will not be considered an Eligible Termination hereunder unless such transfer otherwise constitutes a Good Reason event. Subject to the provisions of Article 6, any participating Employer may, by appropriate action of its board of directors or non-corporate counterpart, terminate its participation in this Plan. Amounts payable hereunder will be paid by the Employer that employs the particular Participant.

Section 8.2 Limitation of Rights. Neither the establishment of the Plan nor any amendment thereof, nor the payment of any benefits, will be construed as giving to any Participant, or other Person any legal or equitable right against Company, any of its Affiliates, or any Person acting on behalf of Company or any of its Affiliates, except as expressly provided herein. Likewise, nothing appearing in or done pursuant to the Plan will be held or construed to create a contract of employment with any Participant or to be consideration for the employment of any Participant. Nothing contained herein will be deemed to (a) give any person the right to be retained in the employ of the Employer, (b) restrict the right of the Employer to discharge any Participant at any time, (c) restrict any Participant's right to terminate employment at any time, or (d) change the "at will" nature of the employment relationship between the Participant and the Employer.

Section 8.3 Governing Law. The provisions of the Plan shall be construed, enforced and administered according to the laws of the State of Delaware, to the extent not preempted by ERISA and any otherwise applicable federal law.

Section 8.4 Jurisdiction and Venue. Exclusive jurisdiction and venue of all disputes arising out of or relating to this plan shall be in any court of appropriate jurisdiction in Midland, Texas, or if such courts do not have jurisdiction or will not accept jurisdiction, in any court of general jurisdiction in the State of Texas. All parties hereby irrevocably consent to the exclusive jurisdiction by any such court with respect to any such proceeding and hereby irrevocably waive, and agree not to assert, by way of motion, as a defense, counterclaim or otherwise (a) any claim that he, she or it is not personally subject to the jurisdiction of the above-named courts for any reason other than by failure to lawfully serve process, (b) that he, she or it or their property is exempt or immune from the jurisdiction of any such court or from any legal process commenced in such courts, and (c) to the fullest extent permitted by applicable law, that (i) the action or proceeding is brought in an inconvenient forum, (ii) the venue of such action or proceeding is improper and (iii) this Plan or the subject matter thereof may not be enforced in or by such courts. The provisions of this Section 8.4 shall survive and remain in effect until all obligations are satisfied, notwithstanding any termination of the Plan.

Section 8.5 Waiver of Trial by Jury. To the extent not prohibited by applicable law, each Participant under this Plan hereby waives, and covenants that he or she shall not assert (whether as plaintiff, defendant or otherwise), their respective right to a jury trial of any permitted claim or cause of action arising out of this Plan, any of the transactions contemplated hereby, or any dealings between any of the parties hereto relating to the subject matter of this Plan or any of the agreements or transactions contemplated hereby. The scope of this waiver and covenant is intended to be all encompassing of any and all disputes that may be filed in any court and that relate to the subject matter of this Plan or any of the transactions contemplated hereby, including, ERISA claims, contract claims, tort claims and all other common law and statutory claims. This waiver and covenant is irrevocable and shall apply to any subsequent amendments, supplements or other modifications to this Agreement.

Section 8.6 No Assignment. Executives will not have any right to pledge, hypothecate, anticipate or assign benefits or rights under this Plan, except by will or the laws of descent and distribution. The provisions of this Plan shall inure to the benefit of and be enforceable by a Participant, his or her Personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees. If a Participant should die before severance benefit payments hereunder have been paid in full, the remaining severance pay benefit payments shall be paid in accordance with the terms of this Plan to his or her surviving spouse, or if there is no surviving spouse to the Participant's surviving children or, if there are no surviving children, to the Participant's estate. The provisions of this Plan, including the Participant covenants herein, shall inure to the benefit of and be enforceable by the Company and its Affiliates, successors and assigns.

Section 8.7 Severability. If any provision of the Plan is held invalid or unenforceable, its validity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included herein.

Section 8.8 Information Requested. Participants or other Persons entitled to benefits hereunder shall provide the Company, the Employer, the Administrator, and their authorized representatives with such information and evidence, and shall sign such documents, as may reasonably be requested from time to time for the purpose of administration of the Plan.

Section 8.9 Basis of Payments to and From Plan. The benefits provided herein will be unfunded and will be provided from the Employers' general assets. No Participant will have any right to, or interest in, any assets of any Employer that may be applied by the Employer to the payment of amounts due hereunder.

ARTICLE 9
DEFINITIONS AND CONSTRUCTION

Section 9.1 Definitions. Wherever used herein, the following terms shall have the following meanings, unless the context clearly requires a different meaning:

(a) "**Accrued Obligations**" means the Participant's unpaid base salary through the Termination Date, any unreimbursed business expenses, and any amount arising from the Participant's participation in, or benefits under, any employee benefit plans, programs or arrangements, which amounts will be payable in accordance with the requirements of applicable law and the terms and conditions of such employee benefit plans, programs or arrangements.

(b) "**Administrator**" means the Compensation Committee of the Board, or its delegate, or such other committee or Person appointed by the Board in accordance with Section 5.1.

(c) "**Affiliate**" means any parent corporation or subsidiary corporation of the Company, whether now or hereafter existing, as those terms are defined in Sections 424(e) and (f), respectively, of the Code and any individual, partnership, corporation, limited liability company, association, joint stock company, trust, joint venture or unincorporated organization that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with the Company. For this purpose "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another, whether through ownership of voting securities, by contract or otherwise.

(d) **"Applicable Factor"** means the relevant factor specified as applicable to the Eligible Senior Executive, as set forth on the attached Schedule B.

(e) "**Average Annual Bonus**" means the average of the annual bonuses, if any, paid or payable to the Participant for the three-year period (or for any shorter period of the Participant's employment, if such Participant has not been employed for three years) immediately preceding the Termination Date. For purposes of clarity, any accelerated payment at target of an annual incentive award upon the occurrence of a change in control under Section 7(i) of the Diamondback Energy, Inc. 2014 Executive Annual Incentive Compensation Plan will be excluded from the calculation of Average Annual Bonus.

(f) "**Beneficial Owner**" has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the Securities Exchange Act of 1934, as amended, except that in calculating the beneficial ownership of any particular Person, such Person will be deemed to have beneficial ownership of all securities that such Person has the right to acquire by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time, the satisfaction of performance goals, or both. The terms "**Beneficially Owns**", "**Beneficial Ownership**" and "**Beneficially Owned**" have a corresponding meaning.

(g) **"Board"** means the Board of Directors of the Company and includes the Compensation Committee of the Board with respect to matters where the Compensation Committee has authority to act on behalf of the Board.

(h) **"Cause"** means a Participant's (i) willful or knowing refusal or failure (other than during periods of illness, physical or mental incapacity) to perform his or her duties in any material respect; (ii) willful misconduct or gross negligence in the performance of duties; (iii) material breach of this Plan, a Participation Agreement, any agreement entered into by Participant related to the Company or its Affiliates, or any Company or Affiliate policy (including any applicable

code of conduct); (iv) breach of any of the Restrictive Covenants provisions in Article 3; (v) conviction of, entry of a guilty plea or a plea of nolo contendere to any criminal act that constitutes a felony or involves, fraud, dishonesty, or moral turpitude; or (vi) indictment for any felony involving embezzlement or theft or fraud.

(i) "**Change in Control**" means:

(i) The direct or indirect sale, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions occurring within a 12-month period, of all or substantially all of the assets of the Company to any Person, where "substantially all" means assets of the Company having a total gross fair market value equal to 40% or more of the total gross fair market value of all of the Company's assets immediately before such transaction or series of transactions;

(ii) The Incumbent Directors cease for any reason to constitute a majority of the Board;

(iii) The adoption of a plan relating to the liquidation or dissolution of the Company;

(iv) Any Person acquires stock of the Company that results in such Person holding Beneficial Ownership of stock of the Company possessing more than 50% of the total fair market value or the total voting power of the Company; or

(v) Any Person acquires, over a 12-month period, Beneficial Ownership of stock of the Company possessing 30% or more of the total voting power of the Company.

(vi) The foregoing notwithstanding, a transaction will not constitute a Change in Control if (A) its sole purpose is to change the state of the Company's incorporation or to create a holding company that will be owned in substantially the same proportions by the Persons who held the Company's securities immediately before such transaction; (B) it constitutes an initial public offering or a secondary public offering that results in any security of the Company being listed (or approved for listing) on any securities exchange or designated (or approved for designation) as a security on an interdealer quotation system; (C) it constitutes a change in Beneficial Ownership that results from a change in ownership of an existing stockholder; or (D) solely because 30% or more of the total voting power of the Company's then outstanding securities is acquired by (1) a trustee or other fiduciary holding securities under one or more employee benefit Plans of the Company or any Affiliate, or (2) any company that, immediately before such acquisition, is owned directly or indirectly by the stockholders of the Company in substantially the same proportion as their ownership of stock in the Company immediately before such acquisition.

(j) "**COBRA**" means the group health plan continuation coverage provisions of the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended

(k) "**Code**" means the Internal Revenue Code of 1986, as amended.

(l) "**Company**" means Diamondback Energy, Inc., a Delaware corporation, and will include its successors and assigns.

(m) "**Continuation Period**" means the period that group health plan continuation coverage under COBRA is available to a Participant whose employment termination results in a loss of group health plan coverage. The Continuation Period commences on the date following the Termination Date when group health plan coverage ends and ends on the earlier of (i) the 18 month anniversary of the loss of coverage date or (ii) the date on which the Participant becomes eligible to receive group health benefits from another employer.

(n) "**Diamondback Parties**" means the Company, its direct and indirect subsidiaries and Affiliates (and each of them, individually, a "**Diamondback Party**")

(o) "**Disability**" means a Participant's inability to substantially perform his or her duties to the Company or any Affiliate by reason of a medically determinable physical or mental impairment for a period of ninety (90) days (whether or not continuous) during any period of three hundred sixty-five (365) consecutive days by reason of physical or mental disability and the Participant has not returned to full-time performance of the Participant's duties within 30 days after written notice of termination is given to the Participant by the Employer. The Administrator will determine whether an individual has a Disability under procedures established by the Administrator. The Administrator may rely on any determination that a Participant is disabled for purposes of benefits under any long-term disability plan maintained by the Company or any Affiliate in which a Participant participates.

(p) "**Effective Date**" means February 20, 2020, the date this Plan was approved by the Compensation Committee of the Board.

(q) "**Eligible Senior Executive**" means an individual who has been designated as an Eligible Senior Executive by the Administrator, selected by the Administrator to participate in the Plan and who has entered into a Participation Agreement with the Company in substantially the forms set forth on the attached Schedule C-1 and Schedule C-2.

(r) "**Eligible Termination**" means (i) a termination of the Participant's employment with the Employer (A) by the Employer without Cause, or (B) by reason of death or Disability, or (ii) a resignation by the Participant for Good Reason.

(s) "**Employer**" means the Company and each of its subsidiaries and Affiliates that adopts the Plan and is treated as an Employer in accordance with the provisions of Section 8.1. Diamondback E&P LLC, a Delaware limited liability company, will be an Employer on the Effective Date, without need for separate action to adopt the Plan.

(t) "**ERISA**" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

(u) **"Good Reason"** means, a Participant's resignation in the event of any (i) material reduction in Participant's base salary, bonus opportunity or severance benefits; (ii) relocation of Participant's principal office more than 25 miles from the current location, or (iii) material diminution in the Participant's position, duties, reporting relationship or authority, which in any case is not cured within thirty (30) business days after written notice thereof by Participant to the Compensation Committee of the Board (which notice must be provided by Participant to the Company within 90 days following the initial occurrence of such event) and an opportunity to cure within the notice period (the "**Cure Period**"). Resignation by the Participant following the Employer's cure or before the expiration of the Cure Period will constitute a voluntary resignation and not a termination or resignation for Good Reason and will not entitle the Participant to any benefits under this Plan. Any termination on account of a Good Reason Resignation must occur within 120 days following the initial occurrence of such event.

(v) "**Incumbent Directors**" means individuals who, on the Effective Date, constitute the Board, provided that any individual becoming a member of the Board subsequent to the Effective Date whose election or nomination for election to the Board was approved by a vote of at least two-thirds of the Incumbent Directors then on the Board (either by a specific vote or by approval of the proxy statement of the Company in which such Person is named as a nominee for election to the Board without objection to such nomination) will be an Incumbent Director. No individual initially elected or nominated as a member of the Board as a result of an actual or threatened election contest with respect to the Board or as a result of any other actual or threatened solicitation of proxies by or on behalf of any Person other than the Board will be an Incumbent Director.

(w) "**Participant**" means a Person who has been designated by the Administrator as an Eligible Senior Executive who may be eligible for benefits under the Plan upon an Eligible Termination.

(x) "**Participation Agreement**" means an agreement between a Participant and the Company, in substantially the forms set forth on the attached Schedule C-1 and Schedule C-2, specifying the Participant's acknowledgement and agreement to the terms of the Plan, including the provisions terminating and superseding the terms any employment agreement or offer letter, the Restrictive Covenant provisions, the forfeiture and clawback provisions and any other terms and conditions that are in addition to or different from those specified in the Plan document. Any Participation Agreement under this Plan is intended to constitute a Service Agreement as defined in and for purposes of the terms of any Award Agreements issued pursuant to the terms of the Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan, the Rattler Midstream Partners LP Long-Term Incentive Plan, the Viper Energy Partners LP 2014 Equity Incentive Plan or such other equity incentive plan adopted or maintained by any Affiliate.

(y) **"Payment Date"** means the first regularly scheduled payroll date that is at least sixty (60) days following the Termination Date.

(z) "**Person**" or "**Persons**" means an individual, partnership, limited liability company, corporation, association, joint stock company, trust, joint venture, labor organization, unincorporated organization, governmental entity or political subdivision thereof, or any other entity, and includes a syndicate or group as such terms are used in Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended.

(aa) "**Plan**" means the Diamondback Energy, Inc. Senior Management Severance Plan, as set forth herein, together with any amendments and supplements hereto as shall be adopted from time to time.

(bb) **"Protection Period"** means the period commencing on the consummation of a Change in Control and ending on the second anniversary of such Change in Control.

(cc) "**Restricted Business**" means any of (i) the oil, gas and gas liquids exploration and production business, (ii) the ownership, operation, development or acquisition of midstream infrastructure assets, including oil, gas and gas liquids gathering and transportation services and water-related gathering, transportation, distribution and disposal services, or (iii) the ownership, acquisition or exploitation of oil and gas properties, in each case, in Texas, Oklahoma and New Mexico and each other area, location or field in which the Diamondback Parties conduct or are preparing to conduct business during the Participant's employment with an Employer or any Affiliate.

(dd) **"Restricted Period"** means, the period of the Participant's employment with the Employer and a period of one year following the termination of the Participant's employment with the Employer for any reason or such applicable shorter period as may be specified pursuant to Section 3.2.

(ee) **"Section 409A"** means Section 409A of the Code and the Department of Treasury rules and regulations issued thereunder.

(ff) "**Service Agreement**" has the meaning set forth in the definition of "Participation Agreement".

(gg) **"Specified Employee"** means a Person who is, as of the date of the Person's termination of employment, a "specified employee" within the meaning of Section 409A, taking into account the elections made and procedures established by the Company.

(hh) "**Termination Date**" means the date that an Eligible Senior Executive's employment with all Employers and Affiliates actually terminates pursuant to an Eligible Termination, as determined by the Administrator.

Section 9.2 Number and Gender. Wherever appropriate herein, a word used in the singular will be considered to include the plural and the plural to include the singular. The masculine gender, where appearing in this Plan, will be deemed to include the feminine gender.

Section 9.3 Headings. The headings of Articles and Sections herein are included solely for convenience and if there is any conflict between such headings and the text of this Plan, the text will control.

[REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK]

To record the adoption of the Plan as set forth herein, effective as of the Effective Date, the Company has caused its duly authorized officer to execute the same this 20th day of February, 2020.

Diamondback Energy, Inc.

By:	/s/ Travis D. Stice
Name:	Travis D. Stice
Title:	Chief Executive Officer

Appendix A

Summary Plan Description Additional Information

ARTICLE 1
OTHER PLAN INFORMATION

Section 1.1 Employer and Plan Identification Numbers. The Employer Identification Number assigned to the Company (which is the "Plan Sponsor" as that term is used in ERISA) by the Internal Revenue Service is 45-4502447. The Plan Number assigned to the Plan by the Plan Sponsor pursuant to the instructions of the Internal Revenue Service is 503.

Section 1.2 Ending Date for Plan's Fiscal Year. The date of the end of the fiscal year for the purpose of maintaining the Plan's records is December 31.

Section 1.3 Agent for the Service of Legal Process. The agent for the service of legal process with respect to the Plan is:

Diamondback Energy, Inc.
500 West Texas
Suite 1200
Midland, TX 79701
Attention: Matt Zmigrosky, General Counsel

Section 1.4 Plan Sponsor and Administrator. The "Plan Sponsor" of the Plan is:

Diamondback Energy, Inc.
500 West Texas
Suite 1200
Midland, TX 79701
Attention: Jennifer Soliman, Executive Vice President, and Chief Human Resources Officer

and the "Plan Administrator" of the Plan is:

Diamondback Energy, Inc.
500 West Texas
Suite 1200
Midland, TX 79701
Attention: Jennifer Soliman, Executive Vice President, and Chief Human Resources Officer

The Plan Sponsor's and Plan Administrator's telephone number is (432) 221-7400. The Plan Administrator is the named fiduciary charged with the responsibility for administering the Plan.

ARTICLE 2
STATEMENT OF ERISA RIGHTS

Participants in this Plan (which is both a welfare benefit plan and a pension benefit plan sponsored by Diamondback Energy, Inc.) are entitled to certain rights and protections under ERISA. If you are designated as an Eligible Senior Executive by the Administrator, selected by the Administrator to participate in the Plan and have entered into a Participation Agreement with the Company, you are considered a Participant in the Plan and, under ERISA, you are entitled to:

Receive Information about Your Plan and Benefits

(a) Examine, without charge, at the Plan Administrator’s office and at other specified locations, such as worksites, all documents governing the Plan and a copy of the latest annual report (Form 5500 Series) filed by the Plan with the U.S. Department of Labor and available at the Public Disclosure Room of the Employee Benefits Security Administration;

(b) Obtain, upon written request to the Plan Administrator, copies of documents governing the operation of the Plan and copies of the latest annual report (Form 5500 Series) and updated Summary Plan Description. The Administrator may make a reasonable charge for the copies; and

(c) Receive a summary of the Plan’s annual financial report. The Plan Administrator is required by law to furnish each participant with a copy of this summary annual report.

Prudent Actions by Plan Fiduciaries

In addition to creating rights for Plan participants, ERISA imposes duties upon the people who are responsible for the operation of the employee benefit plan. The people who operate the Plan, called “fiduciaries” of the Plan, have a duty to do so prudently and in the interest of you and other Plan participants and beneficiaries. No one, including your employer, your union or any other Person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a Plan benefit or exercising your rights under ERISA.

Enforce Your Rights

If your claim for a Plan benefit is denied or ignored, in whole or in part, you have a right to know why this was done, to obtain copies of documents relating to the decision without charge, and to appeal any denial, all within certain time schedules.

Under ERISA, there are steps you can take to enforce the above rights. For instance, if you request a copy of Plan documents or the latest annual report from the Plan and do not receive them within 30 days, you may file suit in a Federal court. In such a case, the court may require the Plan Administrator to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Administrator.

If you have a claim for benefits, which is denied or ignored, in whole or in part, you may file suit in a state or Federal court. In addition, if you disagree with the Plan’s decision or lack thereof concerning the qualified status of a domestic relations order or a medical child support order, you may file suit in Federal court.

If it should happen that Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a Federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the Person you have sued to pay these costs and fees. If you lose, the court may order you to pay these costs and fees, for example, if it finds your claim is frivolous.

Assistance with Your Questions

If you have any questions about the Plan, you should contact the Plan Administrator. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Plan Administrator, you should contact the nearest office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue N.W., Washington, D.C. 20210. You may also obtain certain publications about your rights and responsibilities under ERISA by calling the publications hotline of the Employee Benefits Security Administration.

SCHEDULE A

The multiple of base salary and the number of months that the multiple of base salary will continue to be paid upon a Qualifying Termination outside of the Protection Period is determined based on the position of the Executive as follows:

Position	Multiple of Base Salary	Number of Months
Chief Executive Officer	2x	24
Executive Vice-Presidents	1x	18
Senior Vice-Presidents	1x	15
Vice-Presidents	1x	12

SCHEDULE B

The Applicable Factor used to determine Severance Benefits related to a Change in Control is determined based on the position of the Executive as follows:

Position	Applicable Factor
Chief Executive Officer	3.00
Executive Vice-Presidents	2.50
Senior Vice-Presidents	2.25
Vice-Presidents	2.00

SCHEDULE C-1

PARTICIPATION AGREEMENT
DIAMONDBACK ENERGY, INC.
EXECUTIVE SEVERANCE PLAN

This Participation Agreement (the "**Agreement**") is made and entered into by and between ________________ (the "**Participant**") and Diamondback Energy, Inc., a Delaware corporation (the "**Company**"), effective as of February 20, 2020 (the "**Effective Date**").

The Company maintains the Diamondback Energy, Inc. Senior Management Severance Plan (the "**Plan**") to provide for specified severance benefits in connection with certain Eligible Terminations (as defined in the Plan). You have been selected by the Plan Administrator to be a Participant in the Plan. The Participant hereby acknowledges that Participant has read and understands the terms of the Plan and agrees to participate in the Plan. The Executive also expressly acknowledges and agrees that participation in the Plan replaces and supersedes the Employment Agreement made by and between the Company and the Participant dated ________, and that such Employment Agreement will be terminated and the Participant will no longer be entitled to any benefits under such Employment Agreement upon execution of this Agreement and participation in the Plan.

Participant further acknowledges and agrees that Section 3 of the Plan contains certain Restrictive Covenants, including covenants prohibiting competition, solicitation and disparagement. By signing this Participation Agreement, Participant is subject to the prohibited activities and Restrictive Covenants in Section 3 of the Plan, and Participant acknowledges and agrees that the violation of the provisions of Section 3 of the Plan may result in a loss of benefits under the Plan.

IN WITNESS WHEREOF, each of the parties has executed this Agreement, in the case of the Company by its duly authorized officer, as of the day and year written below, effective as of the Effective Date written above.

DIAMONDBACK ENERGY, INC.		**PARTICIPANT**	
By:	______________________________		______________________________
	Travis Stice, Chief Executive Officer		
Dated:	February __, 2020	Dated:	February __, 2020

SCHEDULE C-2

[PARTICIPATION AGREEMENT FOR TRAVIS D. STICE]

PARTICIPATION AGREEMENT
DIAMONDBACK ENERGY, INC.
EXECUTIVE SEVERANCE PLAN

This Participation Agreement (the "**Agreement**") is made and entered into by and between Travis D. Stice (the "**Participant**") and Diamondback Energy, Inc., a Delaware corporation (the "**Company**"), effective as of February 20, 2020 (the "**Effective Date**").

The Company maintains the Diamondback Energy, Inc. Senior Management Severance Plan (the "**Plan**") to provide for specified severance benefits in connection with certain Eligible Terminations (as defined in the Plan). You have been selected by the Plan Administrator to be a Participant in the Plan. The Participant hereby acknowledges that Participant has read and understands the terms of the Plan and agrees to participate in the Plan. The Executive also expressly acknowledges and agrees that participation in the Plan replaces and supersedes the Employment Agreement made by and between Diamondback E&P LLC, a wholly owned subsidiary of the Company, and the Participant dated April 18, 2014 (the "**Employment Agreement**"), and that such Employment Agreement will be terminated and the Participant will no longer be entitled to any benefits under such Employment Agreement upon execution of this Agreement and participation in the Plan.

Participant further acknowledges and agrees that Section 3 of the Plan contains certain Restrictive Covenants, including covenants prohibiting competition, solicitation and disparagement. By signing this Participation Agreement, Participant is subject to the prohibited activities and Restrictive Covenants in Section 3 of the Plan, and Participant acknowledges and agrees that the violation of the provisions of Section 3 of the Plan may result in a loss of benefits under the Plan.

The parties agree to the following additional provisions that will govern Participant's benefits under the Plan (capitalized terms have the meaning as defined in the Plan), which provisions are intended to maintain certain specified benefits under the Employment Agreement that are consistent with prior public disclosure:

1. The terms of each outstanding equity award granted to Executive by the Company or any Affiliate will provide that such equity award will become 100% vested upon the occurrence of an Eligible Termination.

2. The terms of each outstanding performance based equity award granted to Executive by the Company or any Affiliate will provide that, upon the occurrence of an Eligible Termination that results from a termination of the Participant's employment with the Employer without Cause or a resignation by the Participant for Good Reason, any such outstanding performance based equity award will be determined assuming the performance criteria thereunder had been achieved at the maximum level under the equity award agreement and will be settled within 10 business after the vesting event.

3. Upon the occurrence of an Eligible Termination on account of Participant's death or Disability, in addition to any other benefits that Participant would be entitled to under the Plan,

the Employer will pay one hundred percent (100%) of the premiums to continue Participant's and any of Participant's spouse's and eligible dependents' group health plan continuation coverage under COBRA (provided that such individuals are qualified beneficiaries who are eligible and timely elect COBRA continuation coverage) until the earlier of eighteen (18) months after Participant's termination of employment causes a loss of group health plan coverage and the first date that Participant and Participant's spouse or eligible dependents are covered under another employer's program or the Employer is no longer obligated to offer COBRA continuation coverage to any such qualified beneficiary, provided that the Employer is providing such qualified beneficiaries with group health plan coverage at the time of Participant's termination of employment.

[Signature Page to Follow]

IN WITNESS WHEREOF, each of the parties has executed this Agreement, in the case of the Company by its duly authorized officer, as of the day and year written below, effective as of the Effective Date written above.

DIAMONDBACK ENERGY, INC.	**PARTICIPANT**
By:___________________________________ P. Matt Zmigrosky, Executive Vice President, General Counsel and Secretary Dated: February __, 2020	___________________________________ Travis D. Stice Dated: February __, 2020

Exhibit 21.1

Diamondback Energy, Inc.
Subsidiaries of Registrant

Name of Subsidiary	**Jurisdiction of Incorporation**
Diamondback E&P LLC	Delaware
Diamondback O&G LLC	Delaware
Energen Corporation	Alabama
Energen Resources Corporation	Alabama
EGN Services, Inc.	Alabama
Rattler Midstream GP LLC	Delaware
Rattler Midstream Operating LLC	Delaware
Rattler Midstream LP	Delaware
Tall City Towers LLC	Delaware
Rattler Ajax Processing LLC	Delaware
Rattler OMOG LLC	Delaware
Viper Energy Partners GP	Delaware
Viper Energy Partners LP	Delaware
Viper Energy Partners LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 26, 2020, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Diamondback Energy, Inc. on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said reports in the Registration Statements of Diamondback Energy, Inc. on Forms S-3ASR (File No. 333-218346, effective May 30, 2017), (File No. 333-228584, effective November 29, 2018) and (File No. 333-234764 effective November 18, 2019), and on Forms S-8 (File No. 333-188552, effective May 13, 2013), (File No. 333-215798, effective January 27, 2017), (File No. 333-228637, effective November 30, 2018) and (File No. 333-235671, effective December 23, 2019).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 26, 2020

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 10, 2020 on estimates of proved reserves, future production and income attributable to certain leasehold interest of Diamondback Energy, Inc. (“Diamondback”) as of December 31, 2019. As independent oil and gas consultants, we hereby consent to the inclusion of our report and the information contained therein and information from our prior reserve reports referenced in this Annual Report on Form 10-K of Diamondback (this “Annual Report”) and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Diamondback on Forms S-3ASR (File No. 333-218346, effective May 30, 2017), (File No. 333-228584, effective November 29, 2018) and (File No. 333-234764 effective November 18, 2019), and on Forms S-8 (File No. 333-188552, effective May 13, 2013), (File No. 333-215798, effective January 27, 2017), (File No. 333-228637, effective November 30, 2018) and (File No. 333-235671, effective December 23, 2019).

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas

February 26, 2020

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 10, 2020 on estimates of proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP, a subsidiary of Diamondback Energy, Inc. (“Diamondback”), as of December 31, 2019. As independent oil and gas consultants, we hereby consent to the inclusion of our report and the information contained therein and information from our prior reserve reports referenced in this Annual Report on Form 10-K of Diamondback (this “Annual Report”) and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Diamondback on Forms S-3ASR (File No. 333-218346, effective May 30, 2017), (File No. 333-228584, effective November 29, 2018) and (File No. 333-234764 effective November 18, 2019), and on Forms S-8 (File No. 333-188552, effective May 13, 2013), (File No. 333-215798, effective January 27, 2017), (File No. 333-228637, effective November 30, 2018) and (File No. 333-235671, effective December 23, 2019).

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas

February 26, 2020

EXHIBIT 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

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

Date: February 26, 2020

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Kaes Van't Hof, certify that:

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

Date: February 26, 2020

/s/ Kaes Van't Hof

Kaes Van't Hof
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

I, Travis D. Stice, Chief Executive Officer of Diamondback Energy, Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2019 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date: February 26, 2020

/s/ Travis D. Stice

Travis D. Stice

Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF PERIOD REPORT

I, Kaes Van't Hof, Chief Financial Officer of Diamondback Energy, Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2019 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Date:	February 26, 2020	/s/ Kaes Van't Hof
		Kaes Van't Hof
		Chief Financial Officer

Exhibit 99.1

DIAMONDBACK ENERGY, INC.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2019

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

January 10, 2020

Diamondback Energy, Inc.
500 West Texas, Suite 1210
Midland, Texas 79701

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Diamondback Energy, Inc. (Diamondback) as of December 31, 2019. The subject properties are located in the states of New Mexico and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 7, 2020 and presented herein, was prepared for public disclosure by Diamondback in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Diamondback as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Diamondback Energy, Inc.

As of December 31, 2019

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate – Mbbl	416,226	240,257	656,483
Plant Products – Mbbl	150,179	61,460	211,639
Gas – MMcf	744,023	279,014	1,023,037
MBOE	690,409	348,219	1,038,628
Income Data ($M)			
Future Gross Revenue	$22,880,661	$12,746,650	$35,627,311
Deductions	7,909,371	6,051,309	13,960,680
Future Net Income (FNI)	$14,971,290	$ 6,695,341	$21,666,631
Discounted FNI @ 10%	$ 7,645,177	$ 2,224,738	$ 9,869,915

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Diamondback. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. “Other” costs shown in the cash flow are variable production costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 99.6 percent and gas reserves account for the remaining 0.4 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2019
Discount Rate Percent	Total Proved
5	$13,460,920
15	$7,874,082
20	$6,597,195
30	$5,045,936

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Diamondback's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Diamondback's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Diamondback owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

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 set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator.

Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. Approximately 80 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through December, 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Diamondback or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 20 percent of the proved producing reserves were estimated by analogy, or a combination of methods. These methods were 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 reserves estimates was considered to be inappropriate.

All proved undeveloped reserves included herein were estimated by the analogy method.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Diamondback has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Diamondback with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamondback. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were based on analog well performance and type-curves where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamondback. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Diamondback furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Diamondback. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.69/bbl	$51.79/bbl
	NGLs	WTI Cushing	$55.69/bbl	$15.64/bbl
	Gas	Henry Hub	$2.58/MMBTU	$0.15/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Diamondback and are based on the operating expense reports of Diamondback and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Diamondback. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Diamondback and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Diamondback were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Diamondback's plans to develop these reserves as of December 31, 2019. The implementation of Diamondback's development plans as presented to us and incorporated herein is subject to the approval process adopted by Diamondback's management. As the result of our inquiries during the course of preparing this report, Diamondback has informed us that the development activities included herein have been subjected to and received the internal approvals required by Diamondback's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Diamondback. Diamondback has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Diamondback has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Diamondback were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Diamondback. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Diamondback.

Diamondback makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Diamondback has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Diamondback, of the references to our name, as well as to the references to our third party report for Diamondback, which appears in the December 31, 2019 annual report on Form 10-K of Diamondback. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Diamondback.

We have provided Diamondback with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Diamondback and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

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Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson’s geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2019 continuing education hours, Mr. Robinson attended 32 hours of formalized training including the 2019 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;
(2)wells which were shut-in for market conditions or pipeline connections; or
(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.2

VIPER ENERGY PARTNERS, LP

Estimated

Future Reserves and Income

Attributable to Certain

Royalty Interests

SEC Parameters

As of

December 31, 2019

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

January 10, 2020

Viper Energy Partners, LP
500 West Texas, Suite 1210
Midland, Texas 79701

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain royalty interests of Viper Energy Partners, LP (Viper), a subsidiary of Diamondback Energy, Inc. (Diamondback) as of December 31, 2019. The subject properties are located in the states of New Mexico and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 7, 2020 and presented herein, was prepared for public disclosure by Viper in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Viper as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
Viper Energy Partners, LP

As of December 31, 2019

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate – Mbbl	40,857	13,563	54,420
Plant Products – Mbbl	14,994	3,570	18,564
Gas – MMcf	80,737	15,037	95,774
MBOE	69,307	19,639	88,946
Income Data ($M)			
Future Gross Revenue	$2,317,872	$741,187	$3,059,059
Deductions	58,807	19,176	77,983
Future Net Income (FNI)	$2,259,065	$722,011	$2,981,076
Discounted FNI @ 10%	$1,036,004	$353,004	$1,389,008

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Viper. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. Because the interests evaluated herein are royalty interests, the deductions include only ad valorem taxes. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 98 percent and gas reserves account for the remaining 2 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2019
Discount Rate Percent	Total Proved
5	$1,850,832
15	$1,138,082
20	$977,996
30	$781,477

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Viper's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Diamondback’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing**,** the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Viper owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

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 set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). 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 individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. Approximately 85 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through December, 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Diamondback or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 15 percent of the proved producing reserves were estimated by analogy, or a combination of methods. These methods were 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 reserves estimates was considered to be inappropriate.

All proved undeveloped reserves included herein were estimated by the analogy method.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Diamondback has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Diamondback with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamondback. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were based on analog well performance and type-curves where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamondback. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Diamondback furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Diamondback. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamondback to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.69/bbl	$52.86/bbl
	NGLs	WTI Cushing	$55.69/bbl	$15.79/bbl
	Gas	Henry Hub	$2.58/MMBTU	$0.51/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

As a holder of royalty interests only, Viper bears none of the operating or development costs associated with the underlying properties of this report. Nevertheless, the proved undeveloped reserves in this report have been incorporated herein in accordance with Diamondback’s plans to develop these reserves as of December 31, 2019. The implementation of Diamondback’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Diamondback’s management. As the result of our inquiries during the course of preparing this report, Diamondback has informed us that the development activities included herein have been subjected to and received the internal approvals required by Diamondback’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Diamondback. Diamondback has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, Diamondback has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Viper. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Viper.

Viper makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Viper has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Viper, of the references to our name, as well as to the references to our third party report for Viper, which appears in the December 31, 2019 annual report on Form 10-K of Viper. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Viper.

We have provided Viper with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Viper and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

Val Rick Robisnon, P.E.
TBPE License No. 105137
Managing Senior Vice President

[SEAL]

VRR (DPR)/pl

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2019 continuing education hours, Mr. Robinson attended 32 hours of formalized training including the 2019 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the

structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.