Parsley Energy, Inc.
Form 10-K
February 27, 2019

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

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-36463

PARSLEY ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	46-4314192
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
303 Colorado Street, Suite 3000 Austin, Texas	78701
(Address of principal executive offices)	(Zip Code)

(737) 704-2300
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated

filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	o	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. o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2018 was approximately $8,342,325,852 based on the closing price as reported on the New York Stock Exchange.

As of February 27, 2019, the registrant had 280,162,552 shares of Class A common stock and 36,547,731 shares of Class B common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

PARSLEY ENERGY, INC.
FORM 10-K
ANNUAL PERIOD ENDED DECEMBER 31, 2018

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report on Form 10-K (this “Annual Report”) that express a belief, expectation, or intention, or that are not statements of historical fact, are “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These forward-looking statements include statements, projections and estimates concerning the Company’s operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “intend,” “potential,” “could,” “may,” “foresee,” “plan,” “goal” or other words tha uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if made earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to unduly rely on them. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed under “Item 1A. Risk Factors,” as well as those factors summarized below.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- ability to replace the reserves we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program;
- realized oil, natural gas and natural gas liquids (“NGLs”) prices;
- timing and amount of future production of oil, natural gas and NGLs;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- ability to obtain permits and governmental approvals;
- pending legal or environmental matters;
- marketing of oil, natural gas and NGLs;
- leasehold, minerals or business acquisitions or divestitures;
- costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration, development, production, gathering and sale of oil, natural gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under "Item 1A. Risk Factors."

Additionally, we caution you that reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary note. This cautionary note should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The terms defined in this section are used throughout this Annual Report:

(1) Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used in reference to crude oil, condensate or natural gas liquids.

(2) Boe. One barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

(3) Boe/d. One barrel of oil equivalent per day.

(4) British thermal unit or Btu. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

(5) Free cash flow. A non-GAAP financial measure, which we define as cash flow from operations before changes in operating assets and liabilities less development capital expenditures.

(6) Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

(7) Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(8) Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

(9) Dry hole. 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.

(10) Economically producible. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC's Regulation S-X, Rule 4-10(a)(10).

(11) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the related property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical,

geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are referred to as geological and geophysical costs or G&G costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(12) Exploratory well. A well drilled to find a new field or

to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

(13) Extension well. A well drilled to extend the limits of a known reservoir.

(14) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(15) Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

(16) GAAP. Accounting principles generally accepted in the United States.

(17) Gross acres or gross wells. The total acres or wells, as the case may be, in which an entity owns a working interest.

(18)

Horizontal drilling. A drilling technique where a well is drilled vertically to a certain depth and then drilled laterally within a specified target zone.

(19) Identified drilling locations. Potential drilling locations specifically identified by our management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities.

(20) Lease operating expense. All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

(21) LIBOR. London Interbank Offered Rate.

(22) MBbl. One thousand barrels of crude oil, condensate or NGLs.

(23) MBoe. One thousand barrels of oil equivalent.

(24) Mcf. One thousand cubic feet of natural gas.

(25) MMBoe. One million barrels of oil equivalent.

(26) MMBtu. One million British thermal units.

(27) MMcf. One million cubic feet of natural gas.

(28) Natural gas liquids or NGLs. The combination of ethane, propane, butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

(29) Net acres or net wells. The percentage of total acres or wells, as the case may be, an owner has out of a particular number of gross acres or wells. For example, an owner who has 50% interest in 100 gross acres owns 50 net acres.

(30) NYMEX. The New York Mercantile Exchange.

(31) Operator. The entity responsible for the exploration, development and production of a well or lease.

(32) PE Units. The single class of units that represents membership interests in Parsley Energy, LLC.

(33) Proved developed reserves. Proved reserves 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 with the cost of a new well; or

(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.

(34) Proved reserves. Those quantities of oil and natural 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, within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

(35) Proved undeveloped reserves or PUDs. 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. The following rules apply to PUDs:

(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; and

(iii) Under no circumstances shall estimates for proved 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, or by other evidence using reliable technology establishing reasonable certainty.

(36) Reasonable certainty. A high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

(37) Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new or existing reservoirs in an attempt to establish new production or increase existing production.

(38) Reliable technology. A grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(39) Reserves. 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 prospects 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 market and all permits and financing required to implement the project.

(40) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

(41) SEC. The United States Securities and Exchange Commission.

(42) 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.

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

(44) Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also

called well or borehole.

(45) Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

(46) Workover. Operations on a producing well to restore or increase production.

(47) WTI. West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a

benchmark for other crude oils.

PART I

ITEM 1. BUSINESS

Overview

Parsley Energy, Inc. (either individually or together with its subsidiaries, as the context requires, “we,” “us,” “our” or the “Company”) is an independent oil and natural gas company focused on the acquisition, development, exploration and production of unconventional oil and natural gas properties in the Permian Basin. The Permian Basin is located in west Texas and southeastern New Mexico and is characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. Our properties are located in two sub areas of the Permian Basin, the Midland and Delaware Basins, where, given the associated returns, we focus predominantly on horizontal development drilling.

As of December 31, 2018, we had an interest in 571 gross (442.7 net) productive horizontal wells, of which 467 gross (357.5 net) wells are in the Midland Basin and 104 gross (85.2 net) wells are in the Delaware Basin. As of December 31, 2018, we operated 453 gross (425.3 net) of these horizontal wells and had the rights to develop 267,143 gross (198,946 net) acres in the Permian Basin, with approximately 218,525 gross (154,107 net) acres located in the Midland Basin and 48,618 gross (44,839 net) acres located in the Delaware Basin. We intend to grow our reserves and production through the drilling and development of our multi-year inventory of identified drilling locations.

At December 31, 2018, our estimated proved oil, natural gas and NGLs reserves were 521.7 MMBoe based on an internal reserve report prepared by our internal staff of petroleum engineers and audited by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent third-party petroleum consulting firm. Of these reserves, approximately 60% are classified as proved developed producing. Based on this report, at December 31, 2018, our proved developed reserves were approximately 55% oil, 19% natural gas and 26% NGLs. These calculated percentages include proved developed non-producing reserves.

Our 2019 budget for capital development expenditures is approximately 1,350.0 million to $1,550.0 million, approximately 85% of which is expected to be used for drilling and completions and approximately 15% of which is expected to be used for infrastructure and other expenditures. We expect approximately 30% to 35% of the total budget to be associated with drilling and completions for proved undeveloped reserves as of December 31, 2018. Our capital budget excludes any amounts that may be paid for acquisitions. For the years ended December 31, 2018 and 2017, our aggregate drilling and completion expenditures were $1,510.1 million and $1,049.6 million, respectively, and our infrastructure and other expenditures were $252.1 million and $157.8 million, respectively, for totals of $1,762.2 million and $1,207.4 million, respectively. Of these totals, $308.1 million and $65.1 million were associated with drilling, completions and facility buildout for proved undeveloped reserves for the years ended December 31, 2018 and 2017, respectively. The amount and timing of 2019 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2019 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 working interest owners.

Our Business Strategy

Our business strategy is to increase stockholder value through the following:

- Achieve free cash flow generation through capital efficient development activity. We intend to selectively develop our acreage base and grow production with a strong commitment to capital discipline. By pursuing drilling opportunities offering competitive returns and prioritizing project level rate of return, which is enabled by our deep, high-quality inventory and resource potential, we expect to improve our capital and operational efficiency. In line with these priorities, our 2019 budget contemplates a significant reduction in our outspend, under any commodity price environment, as compared to our 2018 outspend. We believe this balanced and disciplined approach to development will enable sustainable free cash flow generation and favorable returns on invested capital, while, at the same time, increasing our reserves and production.

- Enhance returns through continued improvement in operational and cost efficiencies. We currently operate approximately 96% of our 2018 daily horizontal production and intend to maintain operational control of substantially all of our producing properties. We believe that retaining control of our production will enable us to more efficiently manage the pace and costs of drilling and completion activities, increase recovery rates, lower well costs, improve drilling performance and increase ultimate hydrocarbon recovery through optimization of our drilling and completion techniques. Our management team regularly evaluates our operating results against those of other operators in the area in an effort to improve our performance and implement best practices.

- Optimizing and high-grading our leasehold position. We regularly evaluate and complete acquisitions, divestitures and exchanges of undeveloped leasehold and producing properties that meet our strategic and financial objectives in the ordinary course of our business. We expect these strategic transactions will help us consolidate our core acreage, drill wells with longer lateral lengths, leverage existing infrastructure, maintain adequate inventory life and achieve economies of scale, while divesting of non-core properties that are less economically competitive within our portfolio. We have a proven history of optimizing our leasehold position in the Permian Basin by concentrating our ownership in operated properties with substantial oil-weighted resource potential, and we believe we can continue to economically and efficiently optimize our acreage position to further enhance project returns.

- Maintain financial flexibility. We intend to maintain a conservative financial position to allow us to develop our exploration, drilling and production activities and maximize the present value of our oil-weighted resource potential. Until we achieve self-funded growth through sustainable free cash flow generation, we anticipate funding our growth with a combination of cash on hand, cash flow from operations, borrowings under our revolving credit agreement (“Revolving Credit Agreement”), and strategic divestitures of non-core properties. In limited circumstances, we may also access the capital markets. As of December 31, 2018, we had approximately $1,154.5 million of liquidity, including $163.2 million of cash and cash equivalents. The borrowing base under our Revolving Credit Agreement currently stands at $2.3 billion, with a commitment level of $1.0 billion. As of December 31, 2018, there were no borrowings outstanding and $8.7 million in letters of credit outstanding under our Revolving Credit Agreement as of December 31, 2018, resulting in availability of $991.3 million. Consistent with our disciplined approach to financial management, we have an active commodity hedging program through which we seek to hedge a meaningful portion of our expected oil production, reducing our exposure to downside commodity price fluctuations and enabling us to protect cash flows and maintain liquidity to fund our capital program and investment opportunities.

Our Strengths

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

- Extensive set of reinvestment opportunities. We believe that the majority of our acreage offers stacked pay potential to develop oil and natural gas from several prospective target zones, including, depending on the area, the Spraberry, Wolfcamp, and Bone Spring, and further, that some of these target zones may be characterized by sufficient thickness and resource potential to accommodate more than one pay interval per zone. Through December 31, 2018, we had placed on production 357 gross (326.6 net) horizontal wells in the Midland Basin and 70 gross (67.7 net) horizontal wells in the Delaware Basin. We believe this historical development activity only represents a fraction of our future development potential, providing an extensive inventory of reinvestment opportunities.

- Established resource base and acreage position in the core of the Permian Basin. Our production is exclusively from the Permian Basin in west Texas, an area that has supported oil and gas production since the 1940s. The Permian Basin has well established infrastructure from historical operations, and we believe it also benefits from a relatively stable regulatory environment that has been established over time. As of December 31, 2018, our estimated total proved reserves were composed of approximately 57% oil and 18% natural gas, and 25% NGLs.

- Incentivized management team with substantial technical and operational expertise. Our management team has a proven track record of executing on multi-rig development drilling programs and has extensive experience in the Spraberry and Wolfberry Trends of the Permian Basin. Our management team has an average of 21 years of experience. We have also assembled a robust technical team of petroleum engineers and geologists with an average of 12 years of experience, which we believe will be of strategic importance as we continue to expand our future exploration and development plans. As of December 31, 2018, our executive officers held voting power over approximately 12.4% of our outstanding equity interests. We believe the existence of this significant management ownership position provides meaningful incentive to increase the value of our business for the benefit of all stockholders.

- Operating control over substantially all our horizontal production. As of December 31, 2018, we operated approximately 96% of our 2018 daily horizontal production. We believe that maintaining control of our production enables us to dictate the pace of development and better manage the cost, type and timing of exploration and development activities.

- Conservative balance sheet. We expect to maintain financial flexibility that will allow us to continue our development activities while pursuing selective acquisitions, divestitures and exchanges. As of December 31, 2018, we had $991.3 million of available borrowing capacity under our Revolving Credit Agreement, with no borrowings currently outstanding thereunder. We believe this borrowing capacity, along with cash on hand and cash flow from operations will provide us with sufficient liquidity to execute our current capital program.

Organizational Structure

We are a holding company that was incorporated as a Delaware corporation on December 11, 2013 for the purpose of facilitating our initial public offering (the "IPO") and to become the sole managing member of Parsley Energy, LLC ("Parsley LLC"). As of December 31, 2018, our sole material asset consists of 280,205,293 PE Units and, as sole managing member, we hold a controlling equity interest in Parsley LLC.

Prior to the completion of the IPO, the limited liability company agreement of Parsley LLC (as subsequently amended, the "Parsley LLC Agreement") was amended and restated to modify its capital structure by replacing the different classes of interests previously held by Parsley LLC owners with a single new class of units called "PE Units." In addition, each holder of PE Units ("PE Unit Holder") received one share of our Class B common stock, par value $0.01 per share ("Class B common stock"). Pursuant to the Parsley LLC Agreement, the PE Unit Holders generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of Class B common stock) for shares of our Class A common stock, par value $0.01 per share ("Class A common stock") at an exchange ratio of one share of Class A common stock for each PE Unit (and a corresponding number of shares of Class B common stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications), or, if either we or Parsley LLC so elects, cash (the "Cash Option"). In addition, in connection with the IPO, on May 29, 2014, we entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC and the initial PE Unit Holders and certain other holders of equity in us (each such person, a "TRA Holder"). This agreement generally provides for the payment by us to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state or local income tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of (i) any tax basis increases resulting from the contribution in connection with our IPO by such TRA Holder of all or a portion of its PE Units to us in exchange for shares of Class A common stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A common stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. We will retain the benefit of the remaining 15% of these cash savings.

As a result of the IPO and the related reorganization transactions, we became the sole managing member of and have a controlling equity interest in Parsley LLC. As the sole managing member of Parsley LLC, we operate and control all of the business and affairs of Parsley LLC and, through Parsley LLC and its subsidiaries, conduct our business. We consolidate the financial and operating results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interest in Parsley LLC held by the PE Unit Holders.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and NGLs and certain price and cost information for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Revenues (in thousands):			
Oil sales	$1,536,244	$802,230	$387,303
Natural gas sales (1)	51,231	56,571	30,928
Natural gas liquids sales (1)	227,272	103,193	38,273
Total revenues	$1,814,747	$961,994	$456,504
Average realized prices (2):			
Oil, without realized derivatives (per Bbls)	$60.59	$48.95	$41.34
Oil, with realized derivatives (per Bbls)	58.07	47.68	47.56
Natural gas, without realized derivatives (per Mcf)	1.37	2.43	2.30
Natural gas, with realized derivatives (per Mcf)	1.38	2.40	2.30
Natural gas liquids (per Bbls)	27.21	22.87	16.01
Average price per Boe, without realized derivatives	45.44	38.80	32.60
Average price per Boe, with realized derivatives	43.85	37.94	36.76
Production (1)(2):			
Oil (MBbls)	25,356	16,390	9,368
Natural gas (MMcf)	37,365	23,326	13,463
Natural gas liquids (MBbls)	8,353	4,512	2,390
Total (MBoe)	39,937	24,792	14,002
Average daily production volume:			
Oil (Bbls)	69,468	44,904	25,596
Natural gas (Mcf)	102,370	63,907	36,784
Natural gas liquids (Bbls)	22,885	12,362	6,530
Total (Boe)	109,416	67,923	38,257

(1) Natural gas and NGLs sales and associated production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC Topic 606, Revenue from Contracts with Customers (“ASC 606”),

effective January 1, 2018, as discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption."

(2) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

Approximately 83%, 88% and 90% of our total estimated proved reserves as of December 31, 2018, 2017 and 2016, respectively, were attributable to the Midland Basin, and approximately 17%, 12% and 10% of our total estimated proved reserves as of December 31, 2018, 2017 and 2016, respectively, were attributable to the Delaware Basin. The following table sets forth information regarding our net production of oil, natural gas and NGLs by basin for the periods indicated:

	Year Ended December 31,								
	2018			2017			2016		
	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total
Production (1):									
Oil (MBbls)	18,881	6,475	25,356	14,082	2,308	16,390	8,693	675	9,368
Natural gas (MMcf)	31,873	5,492	37,365	20,835	2,491	23,326	13,134	329	13,463
Natural gas liquids (MBbls)	7,243	1,110	8,353	4,087	425	4,512	2,340	50	2,390
Total (MBoe)	31,436	8,501	39,937	21,641	3,151	24,792	13,222	780	14,002

(1) Natural gas and NGLs sales and associated production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018, as discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption."

Productive Wells

As of December 31, 2018, we had an interest in 571 gross (442.7 net) productive horizontal wells and 1,244 gross (779.7 net) productive vertical wells. Productive wells consist of producing wells and wells mechanically capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of our fractional working interests owned in gross wells. As of December 31, 2018, we owned an immaterial number of productive wells related to the production of natural gas.

Well Operations

As of December 31, 2018, we operated 453 gross (425.3 net) of our horizontal wells and 919 gross (735.7 net) of our vertical wells. As the operator, we design and manage the development of our wells and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the production from the properties we operate, both for our account and for the accounts of third-party working, royalty and overriding royalty interest owners in these properties. We sell our production at market prices to a relatively small number of purchasers, as is customary in the exploration, development and production business. For the years ended December 31, 2018, 2017 and 2016, the following customers accounted for more than 10% of our revenue:

	Year Ended December 31,		
	2018	2017	2016
Shell Trading (US) Company	53%	62%	44%
Lion Oil, Inc.	22%	3%	—%
Targa Pipeline Mid-Continent, LLC	11%	13%	13%
BML, Inc.	1%	2%	13%

If a major customer decides to stop purchasing oil or natural gas from us, our revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers. Please see Note 2—Summary of Significant Accounting Policies—Significant Customers to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Transportation and Delivery Commitments

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The purchaser then transports the oil by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems. In addition, we move the majority of our produced water by pipeline connected to our operated salt water disposal wells rather than by truck. However, due to the inaccessibility of certain of our wells, some produced water will likely always be required to be transported by truck.

We sell oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. During the year ended December 31, 2018, we entered into the following contracts related to the transportation and/or sale of crude oil:

- An amendment to an existing contract providing firm transportation from one of the pipeline systems through which we transport or sell crude oil. Under this amended contract, we have committed to deliver a minimum average volume of 45,000 Bbls/day from January 1, 2019 to June 30, 2025. If a new third party pipeline system commences operations (the "pipeline commencement date") between January 1, 2019 and June 30, 2020, our commitment will increase to a minimum average volume of 60,000 Bbls/day from the pipeline commencement date through June 30, 2020. If the pipeline commencement date occurs before July 1, 2020, our commitment will increase to a minimum average volume of 75,000 Bbls/day from July 1, 2020 through June 30, 2025, and if the pipeline commencement date occurs between July 1, 2020 and June 30, 2025, our commitment will increase to a minimum average volume of 75,000 Bbls/day from the pipeline commencement date through June 30, 2025. In addition, if the pipeline commencement date occurs after June 30, 2025, we will be required to deliver a minimum average volume of 30,000 Bbls/day for five years following the pipeline commencement date; however, if the pipeline commencement date occurs prior to June 30, 2025, such five-year period will be reduced by the period of time from the pipeline commencement date through June 30, 2025.
- A contract for the transportation and/or sale of crude oil, pursuant to which we have committed to deliver approximately 2.7 MMBbl of oil during the period from September 1, 2018 to December 31, 2019. If we fail to deliver the required volumes, we may elect to extend the performance period by three months.
- A contract for the transportation and/or sale of crude oil that is subject to the commencement of operations of a third-party terminal and pipeline system. Upon the commencement of operations, we will be required to deliver a minimum average volume of 5,000 Bbls/day during the first month, which will increase by 5,000 Bbls/day each month until we are required to deliver a minimum average volume of 35,000 Bbls/day during the seventh month. We will then be required to deliver 35,000 Bbls/day until three years following the commencement of operations of the third-party terminal and pipeline system. At the completion of the initial three year period, our counterparty will have the option to extend the contract for up to four additional years, but if such option is not exercised, we will be have the option to extend the contract for up to two additional years.

We have no fixed delivery commitments other than those described above. We expect to fulfill these delivery commitments for the next one to three years with production from our existing proved developed and proved undeveloped reserves, which we regularly monitor to ensure sufficient availability. In addition, we monitor our current production, our anticipated future production and our future development plans, in each case factoring in production attributable to third-party working, royalty and overriding royalty interest owners, in order to meet our delivery commitments. If production volumes are not sufficient to meet these contractual delivery commitments, we may be subject to deficiency fees unless we purchase commodities in the market to satisfy such commitments.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to 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 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 not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons and raising additional capital, which could have a material adverse effect on our business.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger 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.

Segment Information and Geographic Area

Operating segments are defined under GAAP as components of an enterprise that engage in activities from which it may earn revenues and incur expenses and for which separate operational financial information is available and regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on our organization and management, we have only one reportable operating segment, which is oil and natural gas exploration and production. Other services that we engage in are ancillary to our oil and natural gas exploration and producing activities and manage these services to support such activities. All of our operations are conducted in one geographic area of the United States. For additional information, see our consolidated financial statements in this Annual Report beginning on page F-1.

Seasonality of Business

Weather conditions affect the demand for and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the first and fourth quarters, resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Natural Gas Leases

Typically the oil and natural gas lease agreements covering our properties provide 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 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%. Where we own minerals underlying properties that we operate, our net revenue interest will be higher.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced depends on numerous factors beyond our control, the effects of which cannot be accurately predicted or anticipated. Some of these factors include, without limitation, the availability of other domestic and foreign production, the marketing of competitive fuels, the proximity and capacity of pipelines, fluctuations in supply and demand, the availability of a ready market, the effect of United States federal and state regulation of production, refining, transportation and sales and general national and worldwide economic conditions. Additionally, we may experience delays in marketing natural gas production and fluctuations in natural gas prices and our marketing professionals may experience short-term delays in marketing oil due to trucking and refining constraints. There is no assurance that we will be able to market any oil or natural gas produced, or, if such oil or natural gas is marketed, that favorable prices can be obtained.

The United States natural gas market has undergone several significant changes over the past few decades. The majority of federal price ceilings were removed in 1985 and the remainder were lifted by the Natural Gas Wellhead Decontrol Act of 1989. Thus, currently, the price of natural gas in the United States is determined by market forces rather than by regulations. At the same time, the domestic natural gas industry has also seen a dramatic change in the manner in which gas is bought, sold and transported. In most cases, natural gas is no longer sold to pipeline companies. Instead, pipeline companies primarily serve the role of transporter and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

In recent years, oil, natural gas and NGLs prices have been under considerable pressure due to oversupply and other market conditions. Specifically, increased foreign production and increased efficiencies in horizontal drilling, combined with the exploration of newly developed shale fields in North America, have dramatically increased global oil and natural gas production, which has led to lower market prices for these commodities. Given the many uncertainties affecting the supply and demand for oil, natural gas and NGLs, we are unable to accurately predict future oil, natural gas and NGLs prices or the overall effect, if any, that the oversupply of such products and other market conditions will have on our financial condition or results of operations.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress (“Congress”), state governments, the Federal Energy Regulatory Commission (the “FERC”) and other federal and state regulatory agencies and federal, state and local courts. We cannot predict when or whether any such proposals may become effective. We do not believe that such action or proposal would have a material disproportionate effect on us as compared to similarly situated competitors.

Regulation Affecting Production

As described above, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. In addition, all of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the number of oil and natural gas wells 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 NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance 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 limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices for oil, natural gas and NGLs are not currently regulated and therefore are dictated by the prevailing market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and natural gas, or the prices charged for these commodities, 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 oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take statutes and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further, state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC regularly proposes and implements new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that such FERC action would have a material disproportionate effect on our drilling program as compared to other similarly situated natural gas producers.

Gathering services, which occur upstream of FERC jurisdictional transmission services, and which are performed onshore and in state-controlled waters are regulated by state governments. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is conducted on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

In addition to the regulation of natural gas pipeline transportation, the FERC has jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to the FERC's jurisdiction pursuant to the Energy Policy Act of 2005. Under this law, it is unlawful for "any entity," including a producer such as us, that is otherwise not subject to the FERC's jurisdiction under the Natural Gas Act of 1938 to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas, or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud, to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading, or to engage in any act or practice that operates as a fraud or deceit upon any person. The Energy Policy Act of 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 up to $1,269,500 per day per violation (adjusted annually based on inflation) and disgorge profits associated with any violation. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, any market participant, including a producer such as us, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to the FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize or contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist the FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and service conditions for the interstate transportation of liquids, including oil and NGLs, under the Interstate Commerce Act (the "ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

Rates of interstate liquids pipelines are currently regulated by the FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning on July 1, 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. This adjustment is subject to review every five years. Under the FERC's regulations, a liquids pipeline can request the authority to charge market-based rates for transportation service if it satisfies certain criteria, and also can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity. Therefore, requests for service by new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to the FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission (the "FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1,180,566 per violation per day (adjusted annually based on inflation). In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (the "CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement its new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1,191,842 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment and occupational health and safety. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transportation, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While compliance with existing environmental laws and regulations has not had a material adverse effect on our operations to date, we can provide no assurance that this will continue in the future.

The following is a summary of the more significant existing and proposed environmental, occupational health and safety laws and regulations to which our business operations are or may be subject to and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. EPA action in response to the consent decree remains pending. Removal of RCRA's exemption for exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of 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 and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, 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.

We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the “USACE”) or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule redefining the scope of the EPA’s and the USACE’s jurisdiction under the CWA with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands (the “WOTUS” rule). Several legal challenges to the rule followed, along with attempts to stay implementation of the WOTUS rule following the change in U.S. presidential administrations. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the USACE proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intent to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent the original WOTUS rule or any replacement rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

The Oil Pollution Act of 1990 amends the CWA and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures plans.

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act and permitting and enforcement authority may be delegated to state governments. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard for ozone from 75 to 70 parts per billion. The EPA approved final attainment/nonattainment designations with the new ozone standards in July 2018 and currently all of the areas in which we operate are in attainment with such standards. However, state implementation of these revised air quality standards or a change in the attainment status of the areas in which we operate could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. The EPA has also adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. The EPA expanded on its emission standards for volatile organic compounds in June 2016 with the issuance of first-time standards, known as Subpart OOOOa, to address emissions of methane from equipment and processes across the oil and natural gas source category, including hydraulically fractured oil and natural gas well completions. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. These and other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. We do not believe that compliance with such requirements, however, will have a material adverse effect on our operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. Also, as noted above, the EPA has promulgated a New Source Performance Standard related to methane emissions from the oil and natural gas source category.

While Congress has considered legislation related to the reduction of GHG emissions in the past, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations.

Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing. At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal Endangered Species Act (“ESA”) and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the “FWS”) may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency’s 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Administration (“OSHA”) and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2018, nor do we anticipate that such expenditures will be material in 2019.

Employees

As of December 31, 2018, we employed 527 people. We consider our relations with employees to be satisfactory. Our future success will depend in part on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We regularly utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy and information statements and other documents with the SEC under the Exchange Act. The SEC maintains an internet website at www.sec.gov that contains these reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

Our Class A common stock is listed and traded on the New York Stock Exchange (“NYSE”) under the symbol “PE.” Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the offices of the NYSE, at 20 Broad Street, New York, New York 10005.

We also make available free of charge through our website, www.parsleyenergy.com, electronic copies of certain documents that we file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

You should carefully consider the following risks and all of the information contained in this Annual Report. Our business, financial condition and results of operations could be materially and adversely affected by any of these risks. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we consider immaterial also may adversely affect us.

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

Oil, natural gas and NGLs prices are volatile. A sustained period of low commodity prices or decreased demand for hydrocarbons may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenue, profitability, cash flow, access to capital, future rate of growth and the carrying value of our oil and natural gas properties are heavily influenced by the prices we receive for our oil and natural gas production and the prevailing market prices from time to time for oil, natural gas and NGLs. Historically, oil, natural gas and NGLs prices have been volatile and subject to wide fluctuations in response to domestic and international changes in supply and demand, economic and legal forces, events and uncertainties, and numerous other factors beyond our control, including those factors listed below (which list is not exhaustive):

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the level of global exploration and production;
- the level of global oil, natural gas and NGLs inventories;
- the price and quantity of oil, natural gas and NGLs imports to and exports from the U.S.;
- political or economic conditions in or affecting other producing countries and regions, including conflicts or instability in the Middle East, Africa, South America and Eastern Europe;
- actions of the Organization of the Petroleum Exporting Countries, its members and other state-controlled companies relating to oil price and production controls;
- prevailing prices on local price indices in the areas in which we operate and expectations about future commodity prices;
- the proximity, capacity, cost and availability of gathering, transportation, processing, fractionation, refining and export facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting fuel economy, energy supply and energy consumption;
- shareholder activism or activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize emissions of carbon dioxide and methane GHGs;
- the price and availability of alternative fuels and energy sources;
- the effect of energy conservation measures, alternative fuel requirements and increasing demand for alternatives to oil and natural gas;
- the impact of currency fluctuations; and
- domestic, local and foreign governmental regulations, including environmental regulations and taxes.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. The price of oil, natural gas and NGLs decreased significantly in the latter half of 2018 and, as of December 31, 2018, NYMEX WTI oil futures contract prices and NYMEX Henry Hub gas futures prices were $45.41 per barrel and $2.94 per MMBtu, respectively.

A further or extended decline in commodity prices could materially and adversely affect the amount of oil, gas and NGLs that we can produce economically. This may result in our having to make significant downward adjustments to our estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect our ability to replace our production and future rate of growth. In addition, under such conditions, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake similar acquisitions in the future. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and improve our results of operations 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 wells drilled by us in prospects that we pursue will be productive, that we will recover all or any portion of our investment in such unproved property or wells, or that production from wells drilled by us will achieve our desired cash flow and rate of return for all or any portion of our properties.

Development and exploratory 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 or disclosed 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.
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 each of these assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline and we cannot necessarily observe structural and environmental problems during our inspection. 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. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.
Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.
The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition and development of oil and natural gas reserves. During the year ended December 31, 2018, we incurred approximately $1.9 billion for acquisition, exploration and development activities (excluding asset retirement obligations). Our 2019 budget for capital development expenditures is approximately $1,350.0 million to $1,550.0 million, which excludes any amounts that may be paid for acquisitions. Approximately 85% of this budget estimate is expected to be used for drilling and completions and approximately 15% of this budget estimate is expected to be used for infrastructure and other expenditures. The amount and timing of 2019 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2019 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 working interest owners. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity.”
We may finance our future capital expenditures with cash on hand, cash flow from operations, borrowings under our Revolving Credit Agreement and proceeds received from any divestiture of our oil and gas properties. As of December 31, 2018, we had approximately $1,154.5 million of liquidity, with $163.2 million of cash and cash equivalents. The borrowing base under our Revolving Credit Agreement currently stands at $2.3 billion, with a commitment level of $1.0 billion. There were no borrowings outstanding and $8.7 million in letters of credit outstanding as of December 31, 2018, resulting in availability of $991.3 million.
Our cash flow from operations and access to capital, however, are subject to a number of variables beyond our control, including:
- the volume of oil, natural gas and NGLs we are able to produce from existing wells;
- the ratio of oil to natural gas and NGLs we are able to produce from existing wells;
- the prices at which our production is sold;
- our proved reserves;
- our ability to acquire, locate and produce new reserves;
- our ability to borrow under our Revolving Credit Agreement;

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- the global credit and securities markets; and
- the ability and willingness of lenders and investors to provide capital and the cost of such capital.

If our revenues, liquidity or the borrowing base under our Revolving Credit Agreement decrease as a result of lower oil, natural gas and NGLs prices, operating difficulties, declines in reserves or for any other reason, and we require additional capital for our capital expenditure needs, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in the curtailment of our operations relating to development of our properties or the curtailment of acquisitions that may be favorable to us, which in each case could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will likely be required to take write downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our proved and unproved properties for possible impairment. Based on commodity prices and other specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Impairment of Oil and Gas Properties” and Note 14—Disclosures About the Fair Value of Financial Instruments to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our acquisition and development activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to acquire and develop properties depend in part on the evaluation of data obtained through geophysical and geological analysis, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Our reserves estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, the costs involved in drilling, completing and operating our wells are often uncertain before we commence drilling.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations on wastewater disposal, discharge of GHGs, hydraulic fracturing and other potential environmental impacts from our operations, including protections for threatened or endangered plant and animal life;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in the construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse or severe weather conditions or events, including any such conditions or events that may be related to climate change;
- issues related to compliance with environmental regulations;

- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, the presence of naturally occurring radioactive materials and the unauthorized discharge of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGLs prices;
- limited availability of financing at acceptable terms;
- loss of title or other title-related issues and disputes; and
- limitations in the market for oil, natural gas and NGLs.

Our expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified certain drilling locations and prospects on our existing acreage as part of our anticipated future drilling plans. These drilling locations and prospects represent a significant part of our future drilling plans. Our ability to drill and develop these locations depends on a number of factors, including the availability and cost of capital, negotiation of agreements with third parties, commodity prices, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and the availability of water sourcing and distribution systems, regulatory permits and approvals and other factors. In addition, we may alter the spacing between our anticipated drilling locations, which could impact the number of our drilling locations, the number of wells that we drill, and the volumes of oil and gas we ultimately recover. Because of these uncertainties, there can be no assurance that our identified potential well locations will ever be drilled or, if drilled, we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acreage on which our potential drilling locations have been identified, certain of the leases for such acreage may expire. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business and results from operations.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under the applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Revolving Credit Agreement and our senior unsecured notes, will depend on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control and can vary significantly from year to year. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness. If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay planned investments and capital expenditures, or to sell assets, seek additional financing in the debt or equity markets or restructure or refinance our indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict us from pursuing some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a decline in our credit ratings, which could harm our ability to incur additional indebtedness.

In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and may be required to divest of material assets or operations to meet our debt service and other obligations. Our Revolving Credit Agreement and the indentures governing our senior unsecured notes restrict our ability to divest of assets and our use of the proceeds from such divestitures. We may not be able to consummate those divestitures or, if consummated, the proceeds from such divestitures may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not allow us to meet our debt service obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Revolving Credit Agreement and the indentures governing our senior unsecured notes contain a number of significant restrictive covenants, including covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase, or retire our capital stock or subordinated indebtedness;

- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or payments from our restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- form unrestricted subsidiaries.

In addition, our Revolving Credit Agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our Revolving Credit Agreement and the indentures governing our senior unsecured notes impose on us.

Our Revolving Credit Agreement also limits the amount we can borrow up to the lowest of (i) the borrowing base (which currently stands at $2.3 billion), (ii) the aggregate elected borrowing base commitments (which currently stands at $1.0 billion) and (iii) $2.5 billion. The borrowing basis is subject to scheduled annual and other elective borrowing base redeterminations based upon the projected revenues from the oil and natural gas properties securing our loan. As a result of any redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Agreement. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be an event of default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

If we are unable to comply with the various restrictions and covenants in the agreements governing our indebtedness, including our Revolving Credit Agreement and the indentures governing our senior unsecured notes, there could be an event of default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting certain financial ratios and tests, may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil, natural gas and NGLs prices decline, our ability to comply with these covenants may be impaired. We cannot assure you that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests.

In the event of a default under the agreements governing our indebtedness, the lenders under our Revolving Credit Agreement could terminate their commitments to lend and the holders of any of our indebtedness could elect to accelerate and declare all amounts borrowed to be immediately due and payable. A default under our Revolving Credit Agreement could cause a cross-default under the indentures governing our senior unsecured notes, any other indebtedness outstanding and the ISDA Agreements we have entered into as of such default. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for more information about our ISDA Agreements.

If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend the agreements governing our indebtedness or obtain needed waivers on satisfactory terms.

Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of the commodities we sell, we enter into commodity derivative contracts for a significant portion of our production, with an emphasis on oil production, primarily consisting of put spreads, basis swaps and three-way collars. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs.” While intended to reduce the effects of crude oil and natural gas price volatility, such transactions may limit our potential gains if prices rise over the price established by such arrangements. Conversely, our hedging program may be inadequate to protect us from continuing and prolonged declines in the price of crude oil or natural gas.

Global commodity prices are volatile. Such volatility challenges our ability to forecast and, as a result, it may become more difficult to manage our hedging program. In trying to manage our exposure to commodity price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. Hedging transactions may also expose us to the risk of financial loss in certain circumstances, including instances in which: our production is less than expected; there is an increase in the differential between the underlying price in the derivative instrument and the actual prices received; the counterparties to our futures contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs, which could also have an adverse effect on our financial condition.

Our derivative transactions expose us to counterparty credit risk.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions and the contractual terms of the transactions. During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If any of our counterparties were to default on their obligations under a derivative contract, such a default could have a material adverse effect on our results of operations, and could result in a larger percentage of our future production being subject to commodity price changes and could increase the likelihood that our derivative contracts may not achieve their intended strategic purpose.

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

The process of estimating oil and natural gas reserves is complex. Oil and gas reserve engineering is not an exact science; it relies on subjective interpretations of data that may be inaccurate or incomplete and requires predictions and assumptions of future reservoir behavior and economic conditions. Estimates of economically recoverable oil and gas reserves and of future net cash flow depend upon a number of variable factors and assumptions, including:

- the assumed accuracy of field measurements and other reservoir data, including type curve forecast models;
- assumptions regarding expected reservoir performance relative to historical analog reservoir performance;
- the quality and quantity of available data and the interpretation of that data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning the availability of capital and its costs;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves estimates are necessarily subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that we ultimately recover;
- the ratio of oil to gas of the hydrocarbons that we ultimately recover;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred to recover the reserves;
- the amount and timing of future development expenditures; and
- future commodity prices.

In addition, if these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of future net cash flows from our reserves could change significantly. Over time, we may make material changes to

reserves estimates taking into account changes in our assumptions and the results of our development activities and actual drilling, testing and production.

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 reserves.

The present value of future net cash flow from our proved reserves ("Standardized Measure"), and our related PV-10 calculation, may not represent the current market value of our estimated proved reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on 12-month average 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 through 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, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, 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. Therefore, the estimates of Standardized Measure in this Annual Report should not be construed as accurate estimates of the current market value of our proved reserves.

Approximately 24% 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 future oil and natural gas reserves and production and, therefore, our future cash flow and income.

As of December 31, 2018, approximately 24% of our net leasehold acreage was undeveloped or acreage on which wells have not been 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. Unless production is established within a defined period of time on the undeveloped acreage covered by our leases, such leases will expire. 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. Further, to the extent we determine that it is not economic to develop particular undeveloped acreage, we may intentionally allow leases to expire. 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. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. Failing to develop our undeveloped leasehold acreage or allowing leases to expire could result in leasehold abandonment, impairment, charges or a reduction in our oil and natural gas reserves and production, any of which in turn could have a material adverse effect on our financial results. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Impairment of Oil and Gas Properties" and Note 14—Disclosures About the Fair Value of Financial Instruments to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our leasehold abandonments and impairments. For the year ended December 31, 2018, as a result of periodic assessments of our unproved properties that are not held-by-production, we recorded non-cash leasehold abandonment and impairment charges of $127.0 million relating to acreage expiring in future periods because we have no current plans to drill or extend the leases prior to their expiration. For the years ended December 31, 2018, 2017 and 2016, we recognized non-cash leasehold abandonment and impairment expense of $33.8 million, $32.9 million and $6.1 million, respectively, due to leases expiring during those periods.

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.

All of our producing properties are geographically concentrated in the Permian Basin of west Texas. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. 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, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

The marketability of our production is dependent upon vehicles, transportation facilities and other facilities, most of which we do not control. If these vehicles or facilities are unavailable, or if we are unable to access such vehicles or facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.

The marketing of oil, natural gas and NGLs production depends in large part on the availability, proximity and capacity of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. If there is insufficient capacity available on these systems, if these systems are unavailable to us, or if these systems are unavailable to us on commercially reasonable terms, the price offered for our production could be significantly depressed, or we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while we construct or purchase our own facility or system. We also rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transport and sell our oil, natural gas and NGLs production. Our plans to develop and sell our oil and natural gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing facilities to us, especially in areas of planned expansion where such facilities do not currently exist, on commercially reasonable terms or otherwise.

The volume of oil and natural gas that we can produce is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, processing, fractionation, refining or export facilities we utilize, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months and, in many cases, we may be provided only limited, if any, advance notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or any 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 ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water and result in the production of waste water. For example, the hydraulic fracturing process, which we employ to produce commercial quantities of crude oil, natural gas and NGLs, requires the use and disposal of significant quantities of water. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought) could materially and adversely impact our operations. Severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdictions for drilling and hydraulic fracturing in order to protect local water supply. If we are unable to obtain water to use in our operations from local sources, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and gas production operations, including produced water, directly or through the use of third party vendors. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection of produced water resulting from oil and gas activities, which has led to increased public and governmental scrutiny of injection safety. In response to concerns regarding induced seismicity, regulators in Texas have adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity.

Another consequence of water disposal activities and seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells or commercial disposal wells to dispose of produced water. Increased regulation and attention given to water disposal and induced seismicity could also lead to greater opposition, including litigation, to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in limitations on disposal well volumes, disposal rates and pressures or locations, require us or our vendors to shut down or curtail the injection into disposal wells, or cause delays, interruptions or termination of our operations, which events could have a material adverse effect on our business, financial condition and results of operations.

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. Such developments could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Prolonged decreases in production due to decreased developmental activities, production related difficulties or otherwise may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Due to the nature of our drilling programs and the oil and natural gas industry in general, we are party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, throughput volume commitments and drilling commitments. In the event of decreased development activities or production-related difficulties, we could be required to pay for unutilized goods or services or we may be unable to meet these contractual obligations. For additional information, see Note 13—Commitments and Contingencies to our consolidated financial statements included elsewhere in this Annual Report.

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

It is generally 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 leases and underlying mineral interest at the time of acquisition. Rather, we rely upon the judgment of 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. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property. In addition, to the extent title opinions or other investigations prior to the commencement of drilling operations reflect title defects affecting such properties, we are typically responsible for curing any such defects at our expense. The discovery of any such title defects could also delay or prohibit the commencement of drilling operations on the affected properties.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not ultimately be developed or produced.

At December 31, 2018, 40% of our total estimated proved reserves were classified as proved undeveloped. Our 210,404 MBoe of estimated proved undeveloped reserves will require an estimated $2.4 billion of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources, such as cash flow from operations, capital markets and our Revolving Credit Agreement. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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 are related 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.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.
Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing acquisition and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to acquire and develop or find sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease and our business, financial condition and results of operations would be adversely affected. Further, the horizontal decline curve we use to project our future production is subject to numerous assumptions and limitations.
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 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 oil and 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. See “Item 1. Business—Oil and Natural Gas Production Prices and Production Costs—Marketing and Customers.” 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 significant purchasers, 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.
We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormal pressure or irregularities in geological formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources, including as a result of increased seismicity from the disposal of produced water or the underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;

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- suspension or delay of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other 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 commercial quantities. We cannot assure you that the analogues we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- loss of title or other titled related issues;
- abnormal pressure or irregularities in geological formations;
- equipment failure or accidents;
- adverse or severe weather conditions or events;
- reductions in oil, natural gas and NGLs prices;
- political events, public protests, civil disturbances, terrorist acts or cyber-attacks;
- surface access restrictions;
- failure to obtain regulatory and third-party permits and approvals;
- compliance with environmental and other governmental or contractual requirements;
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services;
- oil, natural gas or NGLs gathering, transportation, processing, fractionation, refining and export availability restrictions or limitations; and
- limited availability of financing at acceptable terms.

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 declines or volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGLs 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. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. 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, 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.

In addition, our Revolving Credit Agreement and the indentures governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions. These agreements also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

Our ability to complete divestitures of assets, or interests in assets, may be subject to factors beyond our control, and in certain cases we may be required to retain liabilities for certain matters.

From time to time, we sell an interest in a strategic asset for the purpose of assisting or accelerating the asset’s development. In addition, we regularly review our property base for the purpose of identifying non-strategic assets, the divestiture of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to divest such interests or non-strategic assets or complete announced divestitures, including the receipt of approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the interests or purchase the non-strategic assets on terms and at prices acceptable to us.

Sellers often retain certain liabilities or indemnify buyers for certain pre-closing matters, such as matters of litigation, environmental contingencies, royalty obligations and income taxes. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material.

We are subject to complex U.S. federal, state, local and other laws and regulations related to environmental, occupational, health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, the occupational health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including: (i) the acquisition of a permit before conducting regulated drilling activities; (ii) the restriction of types, quantities and concentration of materials that can be released into the environment; (iii) the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) the application of specific health and safety criteria addressing worker protection; and (v) the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the trend in environmental regulation has been to place more restrictions and limitations on activities

that may affect the environment; if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations, our costs of compliance may increase. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion, and the agency completed attainment/non-attainment designations in July 2018. Although all of the areas in which we operate are currently in attainment, state implementation of the revised NAAQS, or a change in the attainment status of the areas in which we operate, could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.
Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. 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. Moreover, public interest in the protection of the environment has increased dramatically in recent years, and many environmental statutes contain citizen suit provisions that allow private parties to sue to enforce environmental laws and regulations. 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. See "Item 1. Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.
A decline in general economic, business or industry conditions could have a material adverse effect on our results of operations, liquidity and financial condition.
A global economic downturn, particularly with respect to the U.S. economy, and global financial and credit market disruptions could reduce the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, which could in turn result in a further slowdown in economic activity. Reduced worldwide demand for energy often results in lower commodity prices, which will reduce our cash flows and may affect our borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. In addition, 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.
If we experience liquidity concerns, we could face a downgrade in our credit ratings, which could negatively impact our cost of and ability to access capital.
As of December 31, 2018, our long-term senior secured debt was rated B1 with a stable outlook by Moody's Investors Service, Inc. and BB- with a positive outlook by Standard & Poor's Ratings Services. Since this date, no changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.
A downgrade in our credit ratings could negatively impact (i) our costs of capital or our ability to effectively execute aspects of our strategy, (ii) our ability to raise debt in the public debt markets (in which case, the cost of any new debt could be higher than our outstanding debt) and (iii) our ability to obtain additional financing with acceptable interest rates, fees and other terms. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.
The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.
The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in

correlation with oil, natural gas and NGLs prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Further, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages or cost increases could decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 to impose penalties for current violations of up to $1,269,500 per day for each violation (adjusted annually based on inflation) and disgorgement of profits associated with any violation. While our operations have not been regulated by the FERC as a natural gas company under this law, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1 million per day and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to crude oil swaps and futures contracts as that granted to the CFTC with respect to crude oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,162,183 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Item 1. Business—Regulation of the Oil and Natural Gas Industry."

Climate change legislation, regulations restricting emissions of greenhouse gases or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce. In addition, the potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present a danger to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations.

Furthermore, in June 2016, the EPA finalized rules, known as Subpart OOOOa, that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

While Congress has from time to time considered legislation to reduce emissions of GHGs, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulation programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and gas we produce could also have the effect of lowering the value of our reserves.

Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference agreement reached in December 2015, which entered into force in November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Notwithstanding potential risks related to climate change, the

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International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. It should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to causation or contribution to the asserted damage, or to other mitigating factors.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays and could materially and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. The report does not appear to provide a basis for additional federal regulation of hydraulic fracturing at this time.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

Further regulation of hydraulic fracturing at the federal, state and local level could subject our operations to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. Please read "Item 1. Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

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

Oil and natural gas operations in our operating areas may 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 or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. For example, recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties and market oil or natural gas.

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 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. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Because we have fewer financial and human resources than many companies in our industry, we may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons and raising additional capital, which could have a material adverse effect on our business.

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 in recent years. 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 could increase in the future if commodity prices rebound. 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. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our results of operations, liquidity and financial condition.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly over the last several years. Our management believes that our future success depends on our ability to manage the growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burdens; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. As of December 31, 2018, we had placed on production 427 gross (394.3 net) horizontal wells and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. Furthermore, certain of the new techniques we are adopting, such as well-spacing optimization and multi-well pad drilling, may impact the volumes of oil and gas that we ultimately recover and cause irregularities or interruptions in production due to 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 practices. 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, particularly to the extent that development in these areas requires the use of new drilling and completion techniques. 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 worse than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity price declines, 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.

Factors affecting the cost and availability of credit could adversely affect our business.

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

Our ability to use our net operating loss carryforwards may be limited.

As of December 31, 2018, we had approximately $1.4 billion of U.S. federal net operating loss carryforwards (“NOLs”), which begin to expire in 2034. Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an “ownership change” (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of our NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, subject to certain adjustments. Any unused annual limitation may be carried over to later years. We cannot assure you that we will not undergo an ownership change in 2019. However, even if we did have an ownership change in 2019, we do not believe that the resulting Section 382 annual limitation would prevent our utilization of our NOLs prior to their expiration. Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this would adversely affect our operating results and cash flows if we attain profitability.

Our use of 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 pre-drilling 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.
Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity prices, interest rates and other risks associated with our business.
The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The CFTC has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.
The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or such transactions become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap executive facility.
In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.
The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.
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.
Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions.
As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and

controls to monitor and mitigate security threats and to increase security for our information, data, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows. Cybersecurity attacks in particular are becoming more sophisticated and have increased in frequency. We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information and technology systems and networks, as well as those of third parties we use in our operations, may become the target of cybersecurity attacks, including, without limitation, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems and could materially and adversely affect us in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on our ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- a cyber-attack resulting in the loss or disclosure of, or damage to, our or any of our customers' or suppliers' data or confidential information, which could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps;
- a cyber-attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations; and
- a cyber-attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Related to our Common Stock

We are a holding company. Our sole material asset is our equity interest in Parsley LLC and we are accordingly dependent upon distributions from Parsley LLC to pay taxes, make payments under the TRA and cover our corporate and other overhead expenses.

We are a holding company and have no material assets other than our equity interest in Parsley LLC. We have no independent means of generating revenue. To the extent Parsley LLC has available cash, we intend to cause Parsley LLC to make (i) generally pro rata distributions to the PE Unit Holders, including us, in an amount sufficient to allow all such holders, including us, to pay their respective taxes (at assumed tax rates) and to allow us to make payments under the TRA and (ii) non-pro rata payments to us to reimburse us for our corporate and other overhead expenses. We are limited, however, in our ability to cause Parsley LLC and its subsidiaries to make these and other distributions to us due to the restrictions under our Revolving Credit Agreement and the indentures governing our senior unsecured notes. To the extent that we need funds and Parsley LLC or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Our management collectively holds a significant percentage of the voting power of our common stock.

Holders of our Class A common stock and Class B common stock vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our certificate of incorporation. As of December 31, 2018, our executive officers held voting power over approximately 12.4% of our outstanding common stock. The existence of this significant management ownership position may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as the members of our management team continue to control a significant percentage of the voting power of our common stock, they will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their best interests. In any of these matters, the interests of our management team may differ or conflict with the interests of our other stockholders.

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

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption "Item 13. Certain Relationships and Related Transactions and Director Independence." 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.

Our certificate of incorporation and bylaws contain provisions that make it more difficult to effect a change of control of the Company, which may adversely affect the market price of our Class A common stock.

The existence of some provisions of our certificate of incorporation and our bylaws could delay or prevent a change of control of the Company, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, with only approximately one-third of our board of directors elected each year;
- limitations on the removal of directors, including the requirement that a director may only be removed for cause and upon the affirmative vote of the holders of at least two-thirds of the outstanding shares of stock of the Company entitled to vote generally for the election of directors;
- the inability of our stockholders to call special meetings or act by written consent;
- the ability of our board of directors to adopt, alter or repeal our bylaws and the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained for stockholders to amend, alter or repeal our bylaws;
- the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained to amend, alter or repeal any provision of our certificate of incorporation;
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders; 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 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. In addition, certain change of control events have the effect of accelerating any payments due under our Revolving Credit Agreement and the TRA, and could, in certain circumstances, accelerate payments required by the indentures governing our senior unsecured notes, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company. Please see "—In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA."

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

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, to the fullest extent permitted by applicable law, 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, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any director or officer or other employee of ours arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us or any director or officer or other employee of ours that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay dividends on our Class A common stock or Class B common stock in the near future, and our Revolving Credit Agreement and the indentures governing our senior unsecured notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Class A common stock appreciates.

We have never declared or paid any dividends to holders of our Class A common stock or Class B common stock. We currently intend to retain all available funds, if any, to finance the development and expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. Additionally, our Revolving Credit Agreement and the indentures governing our senior unsecured notes place certain restrictions on our ability to pay cash dividends. Consequently, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

There may be future dilution of our common stock, which could adversely affect the market price of our Class A common stock.

In the future, we may issue shares of common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for or that represent the right to receive our common stock. Lastly, we issue restricted share awards, restricted stock units and other incentive compensation to our employees and directors as part of their compensation. Any of these events will dilute our stockholders' ownership interest in us and may reduce our earnings per share and have an adverse effect on the price of our Class A common stock. In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our Class A common stock. This could also impair our ability to raise capital through the sale of our securities.

We are required to make payments under the TRA for certain tax benefits we may claim, and the amounts of such payments could be significant.

The PE Unit Holders generally have the right to exchange their PE Units (and a corresponding number of shares of Class B common stock) for shares of our Class A common stock at an exchange ratio of one share of Class A common stock for each PE Unit (and corresponding share of Class B common stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications), or, if either we or Parsley LLC so elects, cash.

We have entered into the TRA with Parsley LLC and the TRA Holders. The TRA generally provides for the payment by us to each TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of certain increases in tax basis and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 15% of these cash savings. Payments we make under the TRA will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The term of the TRA commenced upon the completion of our IPO and will continue until all tax benefits that are subject to the TRA have been utilized or have expired, unless we exercise our right to terminate the TRA (or the TRA is terminated due to other circumstances, including our breach of a material obligation thereunder or certain mergers or other changes of control), and we make the termination payment specified in the TRA.

Estimating the amount and timing of payments that may become due under the TRA is by its nature imprecise. For purposes of the TRA, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the TRA. The amount and timing of any payments under the TRA are dependent upon significant future events and assumptions, including the timing of the exchanges of PE Units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount of the exchanging TRA Holder's tax basis in its PE Units at the time of the relevant exchange, the depreciation and amortization periods that apply to the increase in tax basis, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the TRA constituting imputed interest or giving rise to depletable, depreciable or amortizable basis.

The payment obligations under the TRA are our obligations and not obligations of Parsley LLC, and we expect that the payments we will be required to make under the TRA could be substantial. We are a holding company with no independent means of generating revenue. Therefore, to the extent Parsley LLC has available cash, we intend to cause Parsley LLC to make pro rata distributions to the PE Unit Holders, including us, in an amount sufficient to allow us to cover all such TRA payment obligations. The ability of Parsley LLC and its subsidiaries to make such distributions will be subject to, among other things, the applicable provisions of Delaware law and restrictions under our Revolving Credit Agreement and the indentures governing our senior unsecured notes (or other applicable instruments issued by Parsley LLC or its subsidiaries). To the extent that we are unable to make payments under the TRA for any reason, such payments will be deferred and will accrue interest until paid. The payments under the TRA are not conditioned upon a holder of rights under the TRA having a continued ownership interest in us.

In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA.

If we experience a change of control (as defined under the TRA, which includes certain mergers, asset sales and other forms of business combinations) or the TRA terminates early (at our election or due to a material breach of the TRA), we would be required to make a substantial, immediate lump-sum payment equal to the present value of hypothetical future payments that could be required to be paid under the TRA (determined by applying a discount rate of one-year LIBOR plus 3%). The calculation of hypothetical future payments will be based upon certain assumptions and deemed events as set forth in the TRA, including that we have sufficient taxable income to fully utilize such benefits and that any PE Units that the TRA Holders or their permitted transferees own on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the termination payment relates.

In these situations, our obligations under the TRA could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction costs a potential acquirer may attribute to satisfying such obligations. For example, if the TRA were terminated at December 31, 2018, the estimated termination payment would be approximately $119.3 million (calculated using a discount rate of LIBOR plus 3%, applied against an undiscounted liability of $242.9 million). The foregoing number is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the TRA.

In the event that our payment obligations under the TRA are accelerated upon certain mergers, other forms of business combinations or other changes of control, the consideration payable to holders of our Class A common stock could be substantially reduced.

If we experience a change of control (as defined under the TRA, which includes certain mergers, asset sales and other forms of business combinations), we would be obligated to make a substantial, immediate lump-sum payment, and such payment may be significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the payment relates. As a result of this payment obligation, holders of our Class A common stock could receive substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. Further, our payment obligations under the TRA will not be conditioned upon the TRA Holders' having a continued interest in us or Parsley LLC. Accordingly, the TRA Holders' interests may conflict with those of the holders of our Class A common stock.

We will not be reimbursed for any payments made under the TRA in the event that any tax benefits are subsequently disallowed.

Payments under the TRA will be based on the tax reporting positions that we will determine. The TRA Holders will not reimburse us for any payments previously made under the TRA if any tax benefits that have given rise to payments under the TRA are subsequently disallowed, except that excess payments made to any TRA Holder will be netted against payments that would otherwise be made, if any, to such holder after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any and may not be able to recoup those payments, which could adversely affect our liquidity.

In certain circumstances, Parsley LLC will be required to make tax distributions to the PE Unit Holders, including us, and such tax distributions may be substantial. To the extent we receive tax distributions in excess of our tax liabilities and obligations to make payments under the TRA and do not distribute such cash balances as dividends on our Class A common stock, the holders of the Exchange Right would benefit from such accumulated cash balances if they exercise their Exchange Right.

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Parsley LLC is treated as a partnership for U.S. federal income tax purposes and, as such, is not subject to U.S. federal income tax. Instead, any taxable income is allocated to the PE Unit Holders, including us. Pursuant to the Parsley LLC Agreement, Parsley LLC will make pro rata cash distributions, or tax distributions, to the PE Unit Holders, including us, in an amount sufficient to allow each of the PE Unit Holders to pay its respective taxes (at assumed tax rates) on such holder's allocable share of any taxable income of Parsley LLC. Under applicable tax rules, Parsley LLC is required to allocate net taxable income disproportionately to its members in certain circumstances. Because tax distributions are determined based on the PE Unit Holder who is allocated the largest amount of taxable income on a per unit basis and on an assumed tax rate that is the highest possible rate applicable to any PE Unit Holder, but are made pro rata based on ownership, Parsley LLC may be required to make tax distributions that, in the aggregate, exceed the amount of taxes that Parsley LLC would have paid if it were taxed on its net income at the assumed rate. The pro rata distribution amounts may also be increased to the extent necessary to ensure that the amount distributed to us is sufficient to enable us to pay any amounts payable under the TRA.

Funds used by Parsley LLC to satisfy its tax distribution obligations will not be available for reinvestment in our business. Moreover, the tax distributions Parsley LLC will be required to make may be substantial, and may exceed (as a percentage of Parsley LLC's income) the overall effective tax rate applicable to a similarly situated corporate taxpayer. In addition, because these payments will be calculated with reference to an assumed tax rate, and because of the disproportionate allocation of net taxable income, these payments may significantly exceed the actual tax liability for many of the PE Unit Holders, including us.

As a result of potential differences in the amount of net taxable income allocable to us and to the other PE Unit Holders, as well as the use of an assumed tax rate in calculating Parsley LLC's tax distribution obligations, we may receive distributions significantly in excess of our tax liabilities and obligations to make payments under the TRA. If we do not distribute such cash balances as dividends on our Class A common stock and instead, for example, hold such cash balances or lend them to Parsley LLC, the holders of the Exchange Right would benefit from any value attributable to such accumulated cash balances as a result of their ownership of Class A common stock following an exchange of their Parsley LLC Units pursuant to the Exchange Right or their receipt of an equivalent amount of cash.

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.

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 (the "Sarbanes-Oxley Act"). Section 404 requires that we document and test our internal control over financial reporting and issue our management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm issue an attestation report on such internal control. 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 our 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 Class A 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties are located in the west Texas portion of the Permian Basin. As of December 31, 2018, our acreage position consisted of 267,143 gross (198,946 net) acres, and approximately 76% of our net acres were held by production. As of December 31, 2018, we had interests in 571 gross (442.7 net) producing horizontal wells, of which we operate 453 gross (425.3 net) of the horizontal wells, and interests in 1,244 gross (779.7 net) producing vertical wells, of which we also operate 919 gross (735.7 net) of the vertical wells.

The Permian Basin extends through multiple counties in west Texas and southeastern New Mexico and covers an area some 250 miles wide and 300 miles long. It is comprised of three main sub-areas, the Midland Basin, the Delaware Basin and the Central Basin Platform. Historically, conventional reservoirs have been targeted and successfully produced in all three sub-areas. Over the past 30 years, there has been an increase in multi-stage fracturing treatments targeting and commingling production from multiple tight, stacked pay, unconventional target zones. With the advent of horizontal drilling and the application of multi-stage fracture treatments within one horizontal wellbore, activity has significantly increased, with operators generally targeting one zone at a time.

Core Area Descriptions

We group our assets by area based on similar geologic, economic and technical requirements. We split our assets into two areas, the Midland Basin and the Delaware Basin.

Midland Basin

Throughout the middle and late Pennsylvanian period, the Midland Basin was a very shallow and generally poorly defined area dominated by marine shale and limestone deposition. Organic content of the marine shale increased as the basin slowly subsided. Tectonic uplift of the Central Basin Platform and the coincident emergence of the Eastern Shelf during the early Permian period brought greater definition to the Midland Basin as a distinct physiographic feature. Slow subsidence and basin filling with organic shale and limestone continued to dominate deposition. During the middle Permian period, more emergent surrounding shelf areas to the northwest and south-southwest contributed thick volumes of clastic sand that molded with the shale and limestone and formed the widespread Spraberry target zone throughout the Permian Basin. In the later Permian period, there was basin-wide infilling and subsequent burial with massive evaporate deposition.

The Midland Basin has historically been characterized by production from its most prolific field, the Spraberry Trend Area. The Spraberry Trend Area has been heavily drilled since the discovery of the Seaboard No. 2-D Lee well in Dawson County, Texas in 1949. The zone stretches over 150 miles north to south and over 75 miles east to west. Additionally, activity targeting the deeper Wolfcamp zone increased dramatically after Henry Petroleum started drilling fully through the Wolfcamp zone in the early 2000s. In the late 2000s and early 2010s, many operators, including us, had success commingling still deeper production from the Upper Pennsylvanian (Cline), Strawn and Atoka zones. Concurrently, operators started testing zones singularly with horizontal wells and multi-stage treatments. To date, operators have drilled horizontal wells in multiple zones within the Midland Basin.

As of December 31, 2018, we held 218,525 gross (154,107 net) acres in our Midland Basin area. Approximately 76% of our net acreage in this area is held by production. We had interests in 467 gross (357.5 net) producing horizontal wells in the Midland Basin as of December 31, 2018, and we operated 364 gross (340.8 net) of the horizontal wells in the Midland Basin. We also had interests in 1,176 gross (767.2 net) producing vertical wells.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2018, we have placed on production 357 gross (326.6 net) horizontal wells in the Midland Basin. The table below summarizes the horizontal wells placed on production in the Midland Basin in the periods indicated:

Year ended December 31, (1)(2)					
2018		2017		2016	
Gross	Net	Gross	Net	Gross	Net
132	127.9	96	89.5	71	64.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells for which there is no production history.

(2) During the periods presented, we have not drilled any dry development wells, productive exploratory wells or dry exploratory wells.

Delaware Basin

From the mid-Pennsylvanian period to the early Permian period, the Delaware Basin was a slowly subsiding area that was characterized by shallow marine shales and limestone. Influxes of clastic sands generally occurred as turbidite deposits formed during periodic sea-level changes. Records indicate a rapid deepening of the Delaware Basin relative to the emergent Central Basin Platform, during the early Permian period. Marine shale deposition continued to dominate the basin during this period. Episodic pulses of carbonate and clastic debris and density flows punctuated the shale deposition and eventually became significant reservoirs. Through the late Permian period, the basin became increasingly more clastic dominated as emergent shelf areas to the north shed sands into the basin.

As of December 31, 2018, we held 48,618 gross (44,839 net) acres in our Delaware Basin area. Approximately 77% of our net acreage in this area is held by production; however, we hold mineral interests in a significant portion of our Delaware Basin leasehold acreage, which ensures our ability to continue producing from this area. As of December 31, 2018, we had interests in 104 gross (85.2 net) producing horizontal wells in the Delaware Basin, of which 89 gross (84.5 net) horizontal wells were operated by us. We also had interests in 68 gross (12.5 net) producing vertical wells in the Delaware Basin as of December 31, 2018.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2018, we have placed on production 70 gross (67.7 net) horizontal wells in the Delaware Basin. The table below summarizes the horizontal wells placed on production in the Delaware Basin in the periods indicated:

Year ended December 31, (1)(2)					
2018		2017		2016	
Gross	Net	Gross	Net	Gross	Net
43	41.9	21	19.9	5	4.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory w