

Parsley Energy, Inc.
Form 10-K
February 29, 2016

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

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	(I.R.S. Employer
of incorporation or organization)	Identification No.)
303 Colorado Street, Suite 3000	78701

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Austin, Texas

(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 ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark 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. ☒

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

Large accelerated filer ☒

Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

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Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2015 was approximately \$1,319,941,307.

As of February 29, 2016, the registrant had 136,623,407 shares of Class A Common Stock and 32,145,296 shares of Class B Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2016 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, 2015

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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 our 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,” “potential,” “could,” “may,” “foresee,” “plan,” “goal” or other words that convey the uncertainty of future results 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 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 rely on them unduly. 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 or business acquisitions;
- 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.

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 would 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.

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.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

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

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

“Boe.” One barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

“Boe/d.” One barrel of oil equivalent per day.

“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.

“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.

“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.

“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.

“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.

“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).

“exploitation.” A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

“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.

“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. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. Refer to the SEC’s Regulation S-X, Rule 4-10(a)(15) for a complete definition of field.

“formation.” A layer of rock which has distinct characteristics that differ from nearby rock.

“GAAP.” Accounting principles generally accepted in the United States.

“gross acres” or “gross wells.” The total acres or wells, as the case may be, in which an entity owns a working interest.

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

“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.

“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.

“LIBOR.” London Interbank Offered Rate.

“MBbl.” One thousand barrels of crude oil, condensate or NGLs.

“MBoe.” One thousand barrels of oil equivalent.

“Mcf.” One thousand cubic feet of natural gas.

“MMBtu.” One million British thermal units.

“MMcf.” One million cubic feet of natural gas.

“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.

“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.

“NYMEX.” The New York Mercantile Exchange.

“operator.” The entity responsible for the exploration, development and production of a well or lease.

“PE Units.” The single class of units, in which all of the membership interests (including outstanding incentive units) in Parsley LLC were converted to in connection with our initial public offering.

“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.

“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, the project within a reasonable time. Refer to the SEC’s Regulation S-X, Rule 4-10(a)(22) for a complete definition of proved oil and natural gas reserves.

“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.

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.

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.

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.

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

“recompletion.” The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish new production or increase existing production.

“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.

“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.

“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.

“SEC.” The United States Securities and Exchange Commission.

“spacing.” The distance between wells producing from the same reservoir. Spacing is often established by regulatory agencies.

“undeveloped acreage.” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

“wellbore.” The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

“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.

“workover” Operations on a producing well to restore or increase production.

“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, the “Company,” “we,” “us” or “our”) is an independent oil and natural gas company focused on the acquisition, development and exploitation of unconventional oil and natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-areas: the Midland Basin, the Central Basin Platform and the Delaware Basin. These areas are 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 primarily located in the Midland and Delaware Basins and our activities have historically been focused on the vertical development of the Spraberry, Wolfberry and Wolfboka Trends of the Midland Basin. Our vertical wells in the Permian Basin are drilled into stacked pay zones that include the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline), Strawn, Atoka and Mississippian formations. In 2015, we transitioned from primarily vertical development drilling activity to predominantly horizontal development drilling activity.

On May 29, 2014, we completed our initial public offering (the “IPO”) of 57.5 million shares of Parsley Energy, Inc.’s Class A Common Stock, par value \$0.01 per share (“Class A Common Stock”), at a price of \$18.50 per share. Approximately 7.5 million of the shares were sold by selling stockholders and we did not receive any proceeds from the sale of those shares. The remaining approximately 50.0 million shares of Class A Common Stock that were sold resulted in gross proceeds of approximately \$924.3 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$867.8 million. A portion of the proceeds from the IPO was used to repay all outstanding borrowings under the revolving credit agreement entered into on September 10, 2013 (as amended, the “Revolving Credit Agreement”), to make a cash payment in settlement of the Preferred Return (as defined herein), to fund the acquisition of certain oil and gas properties and to pay fees and expenses related to the IPO. The remaining proceeds were used to fund a portion of our exploration and development program and for general corporate purposes.

We began operations in August 2008 when we acquired operator rights to wells producing from the Spraberry Trend in the Midland Basin from Joe Parsley, a co-founder of Parker and Parsley Petroleum Company (“Parker and Parsley”). As of December 31, 2015, we continue to operate 37 gross wells. Excluding those legacy 37 wells, as of December 31, 2015, we had an average working interest of 82% in 71 gross (58.2 net) horizontal wells, of which 67 gross (56.7 net) are in the Midland Basin. We operate 99.5% of the wells in which we have an interest and have the rights to develop 142,734 gross (110,967 net) acres in the Permian Basin, with approximately 84,441 net acres located in the Midland Basin. Since we commenced our drilling program in November 2009, we have operated up to 12 rigs simultaneously and averaged four operated rigs for the year ended December 31, 2015. We are currently operating four horizontal rigs and two vertical drilling rigs. The vertical rigs are used primarily to drill the vertical portion of horizontal wells. Our 2016 capital budget contemplates operating three to four horizontal rigs and one to two vertical rigs for 2016.

We intend to grow our reserves and production through the development, exploitation and drilling of our multi-year inventory of identified drilling locations. As of December 31, 2015, we have identified 147 80- and 40-acre potential vertical drilling locations, no 20-acre potential vertical drilling locations and 2,677 potential horizontal drilling locations on our existing acreage, which does not include any locations in our Southern Delaware Basin acreage. We commenced our vertical appraisal drilling program in the Delaware Basin during the first quarter of 2014 and as of the date of this Annual Report, we have drilled and completed three vertical appraisal wells and one horizontal appraisal well. As of December 31, 2015, we had an interest in four gross (1.5 net) wells in this area. We expect to supplement organic growth from our drilling program by proactively leasing additional acreage and selectively pursuing

acquisitions that meet our strategic and financial objectives, with an emphasis on oil-weighted reserves in the Midland Basin.

Our 2016 capital budget for drilling and completion is approximately \$380 million to \$430 million. Our capital budget excludes any amounts that may be paid for acquisitions. For the year ended December 31, 2015, our capital expenditures for drilling and completions were \$400.9 million, as compared to \$491.3 million for the year ended December 31, 2014, excluding, in each period, amounts paid for acquisitions. We expect the average working interest in wells we drill during 2016 will be approximately 90%.

The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

The following table summarizes our technically identified horizontal drilling locations in the Permian Basin as of December 31, 2015:

Area (1)	Net Acreage	Identified Drilling Locations(2,3)
Midland Basin-Core	59,895	1,979
Midland Basin-Tier I	17,227	698
Midland Basin-Other	7,319	—
Southern Delaware Basin (4)	26,526	—
Total Permian Basin	110,967	2,677

(1) Please see “Item 2. Properties.”

(2) We have estimated our drilling locations based on well spacing assumptions for the areas in which we operate and other criteria. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in our adding additional proved reserves to our existing proved reserves. Also see “Item 1A. Risk Factors.”

(3) Our target horizontal location count implies 660’ to 990’ between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

(4) Please see “Item 2. Properties—Delaware Basin.”

Our total identified vertical drilling locations include 147 vertical locations on 80- and 40- acre spacing and no vertical locations on 20-acre spacing associated with proved undeveloped reserves as of December 31, 2015. Of these 147 vertical locations, 135 are in our Midland Basin-Core area, and 12 are in our Midland Basin-Tier I area. An additional 1,300 vertical locations at 80- and 40-acre spacing have been identified throughout our acreage position, but are not included in the proved undeveloped reserves.

At December 31, 2015, our estimated proved oil and natural gas reserves at December 31, 2015, were 123.8 MMBoe based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent reserve engineers. Our proved reserves are approximately 60% oil, 21% natural gas, 19% NGLs and 42% proved developed.

Our Business Strategy

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

Grow reserves, production and cash flow by exploiting our liquids rich resource base. We intend to selectively develop our acreage base in an effort to maximize its value and resource potential. We intend to pursue drilling opportunities that offer competitive returns that we consider to be low risk based on production history and industry activity in the area, and repeatable as a result of well-defined geological properties over a large area. Through the conversion of our resource base to developed reserves, we will seek to increase our reserves, production and cash flow while generating favorable returns on invested capital.

Improve operational and cost efficiency by maintaining control of our production. We currently operate approximately 98% of the wells in which we have an interest 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 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. We have reduced the average time from spud to rig release for our horizontal Spraberry and Wolfberry wells from approximately 34 days during the fourth quarter of 2014 to approximately 22 days in the fourth quarter of 2015. Our average total depth of horizontal wells drilled in 2015 was 16,440 feet. We have also reduced our total horizontal drilling, completion and facilities costs from an average of \$8.4 million per well in the fourth quarter of 2014 to an average of \$6.7 million per well in the fourth quarter of 2015. This decrease was driven primarily by a reduction in hydraulic fracturing costs and efficiencies gained through economies of scale over this time period. Additionally, we initiated cost reduction discussions with our suppliers beginning in November 2014.

Pursue additional leasing and strategic acquisitions. We regularly evaluate and complete acquisitions of undeveloped leasehold and producing properties that meet our strategic and financial objectives in the ordinary course of our business, with a focus primarily on our Midland Basin-Core area, while selectively pursuing other acquisition opportunities that meet our strategic and financial objectives. Our acreage position extends through what we believe are multiple oil and natural gas producing stratigraphic horizons in the Midland Basin, and we believe we can economically and efficiently add and integrate additional acreage into our current operations. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential and believe our management team's extensive experience operating in the Midland Basin provides us with a competitive advantage in identifying leasing opportunities and acquisition targets and evaluating resource potential. Maintain financial flexibility. We intend to maintain a conservative financial position to allow us to develop our drilling, exploitation and exploration activities and maximize the present value of our oil-weighted resource potential. We intend to fund our growth with cash flow from operations, liquidity under our Revolving Credit Agreement and access to capital markets over time. As of December 31, 2015, we had approximately \$918.9 million of liquidity, with \$344.2 million of cash and cash equivalents and \$574.7 million of available borrowing capacity under our Revolving Credit Agreement. Our borrowing base under the Revolving Credit Agreement currently stands at \$575.0 million. Consistent with our disciplined approach to financial management, we have an active commodity hedging program that seeks 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. At December 31, 2015, a significant portion of our expected 2016 oil production was hedged.

Our Strengths

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

Extensive horizontal development potential. We believe there are a significant number of horizontal locations on our acreage that will allow us to target the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline) and Atoka shales. In addition, based on our analysis of data acquired through our drilling program and the activities of offset operators, we believe that multiple benches contained within our acreage may have significant resource potential, which could substantially increase the ultimate hydrocarbon recovery of each surface acre we have under leasehold. Excluding our Southern Delaware Basin acreage, we had 2,677 identified horizontal drilling locations as of December 31, 2015. We initiated our horizontal development program in 2013 and are currently operating four horizontal rigs and two vertical rigs, which are primarily used to drill the vertical portion of horizontal wells. Through December 31, 2015, we have drilled and completed 60 gross (51.0 net) horizontal wells in the Midland Basin and one gross (0.9 net) horizontal wells in the Delaware Basin, and as we continue to develop our Southern Delaware Basin acreage, we expect to identify additional horizontal drilling locations in that area. We believe that our 596 gross (372.9 net) vertical wells provide a stable production base from which to grow our horizontal drilling program.

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 extensive experience in the Spraberry, Wolfberry and Wolftoka Trends of the Permian Basin. Our chief executive officer, Bryan Sheffield, is a third generation oil and gas executive, and our management team has an average of 17 years of experience. We have also assembled a technical team that includes 15 petroleum engineers and seven geologists with an average of 13 years of experience, which we believe will be of strategic importance as we continue to expand our future exploration and development plans. Our executive officers hold approximately 27.1% of our ownership interest and is our largest stockholder group. We believe our executive officers' significant ownership interest provides meaningful incentive to increase the value of our business for the benefit of all stockholders.

Operating control over approximately 98% of our production. As of December 31, 2015, we operated approximately 98% of the wells in which we have an interest. 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, exploitation and development activities. Our leasehold position is comprised primarily of properties that we operate and, excluding

Southern Delaware Basin acreage, includes an estimated 2,677 potential horizontal drilling locations and 147 80- and 40-acre potential vertical drilling locations.

Conservative balance sheet. We expect to maintain financial flexibility that will allow us to develop our drilling activities and selectively pursue acquisitions. As of December 31, 2015, we did not have any debt outstanding under our Revolving Credit Agreement and had \$574.7 million of available borrowing capacity. We believe this borrowing capacity, along with our cash flow from operations, will provide us with sufficient liquidity to execute our current capital program.

Recent Events

Recent Horizontal Well Results

The following table provides a summary of all wells completed during the fourth quarter of 2015 that have sufficient production data:

	Well	IP Rate	90-Day		
			30-Day	Average	Average
			Average	Cumulative	Total
			Production	Depth	
Area	Count	(Boe/d)	(Boe)	(feet)	
Midland Basin – Core	5	727	(1) 50,143	16,238	
Midland Basin – Tier I	2	430	(2) 33,953	14,822	

(1) Consisting of 589 Bbls/d of oil, 352 Mcf/d of natural gas, and 79 Bbls/d of NGLs.

(2) Consisting of 365 Bbls/d of oil, 203 Mcf/d of natural gas, and 31 Bbls/d of NGLs.

Recent Activity

In December 2015, the Company sold its interest in 91 net operated wells and 11,664 gross (7,155 net) acres in north Martin and south Dawson Counties, Texas, for net proceeds of \$39.4 million and realized a \$36.7 million dollar loss, net of estimated purchase price adjustments.

During the first quarter of 2016, we acquired certain undeveloped acreage and producing oil and gas properties located adjacent to our existing operating areas in Upton, Reagan, and Glasscock Counties for an aggregate purchase price of \$148.5 million, of which a deposit of \$10.0 million was paid in December 2015. The acquisition added 260 gross (227 net) horizontal drilling locations across 6,040 gross (5,274 net) surface acres and production from three producing horizontal wells. The acquisition also included one drilled horizontal well that was completed by the seller prior to the transaction closing in January 2016.

Issuance of Class A Common Stock

On February 5, 2015, we entered into an agreement to sell 14,885,797 shares of our Class A Common Stock in a private placement (the “Private Placement”) at a price of \$15.50 per share to selected institutional investors. The Private Placement closed on February 11, 2015, and resulted in gross proceeds of approximately \$230.7 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$224.0 million. The net proceeds were used to repay a portion of our outstanding borrowings under our Revolving Credit Agreement and for general corporate purposes.

On September 18, 2015, we entered into an agreement to sell 14,950,000 shares of our Class A Common Stock (including 1,950,000 shares pursuant to the underwriters' option to purchase additional shares) at a price of \$15.00 per share in an underwritten public offering (the "September Offering"). The September Offering resulted in gross proceeds of approximately \$224.3 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$217.0 million. A portion of the net proceeds were used to repay borrowings outstanding under our Revolving Credit Agreement. The remainder of the net proceeds are expected to be used to fund a portion of our capital program, which may include acquisitions.

On December 9, 2015, we and NGP X US Holdings, L.P., one of our stockholders ("NGP"), entered into an agreement to sell an aggregate of 14,202,500 shares of Class A Common Stock, including 12,911,364 shares of Class A Common Stock issued and sold by us and 1,291,136 shares of Class A Common Stock sold by NGP at a price of \$18.00 per share in an underwritten public offering (the "December Offering"). On December 10, 2015, the underwriters exercised in full their option to purchase additional shares. The December Offering resulted in gross proceeds of approximately \$228.7 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$228.4 million. A portion of the net proceeds from the offering were used to fund the acquisition of 6,040 gross (5,274 net) acres located in Upton, Reagan and Glasscock Counties, Texas, and the remaining net proceeds are expected to be used to fund a portion of our capital program and for general corporate purposes. We did not receive any of the proceeds from the sale of shares by NGP.

Upon completion of each of the Private Placement, September Offering and the December Offering, we contributed all of the net proceeds to Parsley LLC in exchange for an aggregate of 42,747,161 PE Units. As a result, our ownership of Parsley LLC increased to 81.0%, with the PE Unit Holders' ownership of Parsley LLC decreasing to 19.0%.

Organizational Structure

We are a holding company that was incorporated as a Delaware corporation on December 11, 2013 for the purpose of facilitating the IPO and to become the sole managing member of Parsley Energy, LLC, which we refer to as “Parsley LLC”. Our principal asset is a controlling equity interest in Parsley LLC. On May 22, 2014, a registration statement filed on Form S-1 with the SEC related to shares of Class A Common Stock was declared effective. The IPO closed on May 29, 2014.

After the effective date of the registration statement but prior to the completion of the IPO, the limited liability company agreement of Parsley LLC 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 PE Unit holder received one share of our Class B Common Stock (“Class B Common Stock”). Pursuant to such amended and restated limited liability company agreement (the “Parsley Energy LLC Agreement”), each PE Unit holder has the right to exchange their PE Units together with an equal number of shares of our Class B Common Stock, for shares of our Class A Common Stock (or cash at our or Parsley LLC’s election (the “Cash Option”)) on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications (the “Exchange Right”). In addition, in connection with the IPO, we entered into a Tax Receivable Agreement (the “TRA”) with Parsley LLC, the PE Unit holders and certain of our other equity owners (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 Parsley Energy, Inc. actually realizes (or is deemed to realize in certain circumstances) in periods after the IPO as a result of (i) any tax basis increases resulting from the contribution in connection with the 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. See “Certain Relationships and Related Transactions, and Director Independence” and “Management’s Discussion and Analysis of Financial Conditions and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Corporate Reorganization.” These transactions are collectively referred to as the “Reorganization Transactions.”

As a result of the IPO and the related Reorganization Transactions, we became the sole managing member of, and has 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 results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interest in Parsley LLC held by the Parsley LLC Unit holders.

The following diagram indicates our organizational structure as of February 29, 2016. This chart is provided for illustrative purposes only and does not represent all legal entities affiliated with us.

(1) Includes Parsley Finance Corp.

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Oil and Natural Gas Production Prices and Production Costs

Production and Price History

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

	Year Ended December 31,		
	2015	2014	2013
Revenues (in thousands, except percentages):			
Oil sales	\$215,795	\$232,554	\$97,839
Natural gas sales	26,582	30,642	23,179
Natural gas liquids sales (1)	23,680	38,561	—
Total revenues	\$266,057	\$301,757	\$121,018
Average realized prices(2):			
Oil sales, without realized derivatives (per Bbls)	\$44.89	\$81.91	\$93.28
Oil sales, with realized derivatives (per Bbls)	56.60	81.33	87.91
Natural gas, without realized derivatives (per Mcf)	2.57	4.23	4.95
Natural gas, with realized derivatives (per Mcf)	2.72	4.32	4.95
NGLs sales (per Bbls)	15.79	33.83	—
Average price per Boe, without realized derivatives	33.13	58.19	66.17
Average price per Boe, with realized derivatives	40.33	58.00	63.09
Production (3):			
Oil (MBbls)	4,807	2,839	1,049
Natural gas (MMcf)	10,339	7,245	4,680
Natural gas liquids (MBoe) (1)	1,500	1,140	—
Total (MBoe)	8,031	5,186	1,829
Average daily production volume:			
Oil (Bbls/d)	13,170	7,778	2,874
Natural gas (Mcf/d)	28,326	19,849	12,822
Natural gas liquids (Boe/d)	4,110	3,123	—
Total (Boe/d)	22,003	14,207	5,011

(1) For the year ended December 31, 2013, NGLs sales and production are included in the natural gas line item.

(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.

(3) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency.

This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Productive Wells

As of December 31, 2015 we owned an average 82% working interest in 71 gross (58.2 net) productive horizontal wells. As of December 31, 2015 we owned an average 68% working interest in 596 gross (372.9 net) productive vertical wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

General

As of December 31, 2015, we operated approximately 99.5% of the wells in which we have an interest. As operator, we design and manage the development of a well 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 properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2015, four purchasers each accounted for more than 10% of our revenue during the period: Shell Trading (US) Company, BML, Inc. (“BML”), Targa Pipeline Mid-Continent, LLC (“Targa”), and Transoil Marketing, LLC. For the year ended December 31, 2014, five purchasers each accounted for more than 10% of our revenue during the period: Targa, Plains Marketing, LP (“Plains”), BML, Permian Transport & Trading (“PTT”) and Enterprise Crude Oil, LLC (“Enterprise”). For the year ended December 31, 2013, four purchasers, PTT, Plains, Enterprise and Targa, each accounted for more than 10% of our revenue. No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a materially 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.

Transportation

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 system.

In addition, we move the majority of our produced water by pipeline connected to commercial 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 taken away by truck. We believe that the completion of gathering systems, the connection to salt water disposal wells and other actions will help us to reduce our lease operating expense in future periods.

In the third quarter of 2014, we entered into an agreement with a private midstream services company for firm pipeline capacity from our North Upton County and South Midland County acreage to Colorado City, Texas, which enables us to bypass the Midland pricing market for a substantial portion of our crude oil production when pipeline deliveries commence. As of December 31, 2015, approximately 43% of our gross oil production was being transported by this pipeline.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These

companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

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 generally accepted accounting principles as components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is 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. We consider drilling rig services ancillary to our oil and 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 and combined 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 fourth and first 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

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced, if any, will depend on numerous factors beyond our control, the effect of which factors 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 United States natural gas market is operating in a free market environment in which the price of gas 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 a pipeline company. Instead, the pipeline company now serves the role of transporter primarily, and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

Recently, oil and natural gas 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 exploration of newly developed shale fields in North America have dramatically increased global oil and natural gas production, which has led to significantly lower market prices for these commodities. In view of the many uncertainties affecting the supply and demand for oil, natural gas, and NGLs, we are unable to predict future oil and natural gas prices or the overall effect, if any, that the decline in demand for and the oversupply of such products 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 Congress, the states, the Federal Energy Regulatory Commission (the “FERC”) and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

Natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. 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 which 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 ratable or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGLs and gas 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 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 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 of gas, oil, condensate and NGLs are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States 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 potentially 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 by the partnership, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take 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 is continually proposing and implementing 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 our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the Energy Policy Act of 2005 ("EPA 2005"). Under the EPA 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the Natural Gas Act of 1938 ("NGA") 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 FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of 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. EPA 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to \$1.0 million per day per 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, 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 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, 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 FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and service conditions for interstate transportation of oil, including NGLs, under the Interstate Commerce Act ("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 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 FERC.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. For the five-year period beginning on July 1, 2016, 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 FERC's regulations, a liquids pipeline 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 for the partnership.

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 or for new shippers. Therefore, 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 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 ("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 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("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 their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of \$1 million 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 is 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 transport, 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, 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 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"), the individual states 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, from time to time various environmental groups have challenged the EPA's

exemption of certain oil and gas wastes from RCRA. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on 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 performance of 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 (“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, new EPA and USACE rules defining the scope of the EPA’s and the USACE’s jurisdiction became effective. To the extent the 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. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. 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 be substantial.

The Oil Pollution Act of 1990 (“OPA”), amends the Clean Water Act and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, OPA requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures (“SPCC”) plans. We continue to review our properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

Safe Drinking Water Act

In the course of our operations, we produce water in addition to oil and 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 (“SDWA”) and permitting and enforcement authority may be delegated to the states. 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 gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. In response to these concerns, regulators in some states are considering additional requirements related to seismic safety. For example, the RRC has adopted new permit rules for injection wells to address these seismic activity concerns within the state. 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. These new rules could impact the availability of injections 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 our reduce profitability; however, these costs are commonly incurred by all oil and gas producers and we do not believe that the costs associated with the disposal of produced water 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, for example, 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. The need to obtain permits has the potential to delay the development of oil and natural gas projects. 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 (“NAAQS”) for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS 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. In addition, the EPA has 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. More recently, in August 2015, the EPA announced proposed rules that would establish new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities. The EPA’s proposed rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package would extend existing VOC standards under the EPA’s Subpart OOOO of the New Source Performance Standards (“NSPS”) to include previously unregulated equipment within the oil and natural gas source category. Compliance with this rule will require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. 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. However, we do not believe that compliance with such requirements 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”) present an endangerment 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 Prevention of Significant Deterioration (“PSD”) permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established on a case-by-case basis. 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 monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Recently, in December 2015, the EPA finalized rules that added new sources to the scope of the greenhouse gases monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. In addition, as noted above, the EPA has proposed an NSPS related to methane emissions from the oil and natural gas source category as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to

45% from 2012 levels by 2025. Additional federal action with respect to the control of methane emissions is likely.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. 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. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some 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 and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production 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, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Also, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Further, the EPA proposed regulations under the CWA in April 2015 prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board. In addition, the U.S. Department of the Interior finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

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 government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. 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 could incur potentially 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 may designate critical habitat and suitable habitat areas that it believes are necessary for 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. For example, in March 2013, the U.S. Fish and Wildlife Service ("FWS") listed the lesser prairie chicken as a threatened species under the ESA. Although the lesser prairie chicken's habitat includes areas of the Permian Basin, where we operate, we do not believe that this listing will have a significant impact on our operations. Moreover, as a result of a 2011 settlement agreement, the FWS is 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. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and gas companies after dead migratory birds were found near reserve pits associated with drilling activities and represents an area of increased enforcement. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our

exploration and production activities that could have an adverse impact on our ability to develop and produce 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 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. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

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 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 can in certain cases 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 materially 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 2015, nor do we anticipate that such expenditures will be material in 2016.

Employees

As of December 31, 2015, we employed 212 people. 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 consider our relations with our employees to be satisfactory. From time to time we 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 statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549, on official business days during the hours of 10 a.m. to 3 p.m. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

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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 and natural gas prices are volatile and have declined significantly over the past year. An extended continuation of low, or a further decline in, commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments

Prices for oil and natural gas can fluctuate widely and have declined significantly over the past year. For example, from 2013 to 2015, NYMEX WTI crude oil prices ranged from a high of \$110.53 per barrel on September 6, 2013 to a low of \$26.21 per barrel on February 11, 2016. Average daily prices for NYMEX Henry Hub gas ranged from a high of \$6.15 MMBtu during 2014 to a low of \$1.76 per MMBtu during 2015. The duration and magnitude of the recent decline in crude oil prices cannot be predicted. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;
- the price and quantity of foreign imports;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

In recent months, prices for U.S. crude oil have weakened in response to a buildup in inventories and lower global demand. An announcement by the Organization of the Petroleum Exporting Countries in December 2015, in which the organization indicated it would not put a production ceiling in place, further depressed crude prices.

Lower commodity prices will reduce our cash flows and borrowing ability. 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. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease, a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a continuation of low, or 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.

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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 acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our 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 or that we will recover all or any portion of our investment in such unproved property or wells.

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

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

Our exploitation, development and exploration 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 exploitation, development and acquisition of oil and natural gas reserves. We expect to fund 2016 capital expenditures with cash generated by operations, borrowings under our Revolving Credit Agreement and possibly through additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our Revolving Credit Agreement. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity.”

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Revolving Credit Agreement.

If our revenues or the borrowing base under our Revolving Credit Agreement decreases as a result of a continuation of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, 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 flow generated by our operations or available borrowings under our Revolving Credit Agreement are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations.

Future price declines could result in a reduction in the carrying value of our proved oil and gas properties, which could adversely affect our results of operations.

Commodity prices have declined significantly from 2014. Through February 22, 2016, oil prices have declined from a high of \$107.26 per Bbl on June 20, 2014 to a low of \$26.21 per Bbl on February 11, 2016, and gas prices have declined from a high of \$6.15 per Mcf on February 19, 2014 to a low of \$1.76 per Mcf on December 17, 2015. Likewise, NGLs have suffered significant recent declines. NGLs are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. As stated above, price declines, as have occurred recently, could result in downward adjustments to our estimated proved reserves. It is possible that prices could decline further, or our estimates of production or other economic factors could change to such an extent that we may be required to impair, as a noncash charge to earnings, the carrying value of our oil and gas properties. We are required to perform impairment tests on proved oil and gas properties whenever events or changes in circumstances indicate that the carrying value of proved properties may not be recoverable. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and gas properties, the carrying value may not be recoverable and therefore an impairment charge would be required to reduce the carrying value of the proved properties to their fair value. See Impairment of Oil and Gas Properties included in "Part 2. Item 7. Management's Discussion and Analysis" for specific information regarding our impairments. We may incur impairment charges in the future, which could materially affect our results of operations in the period incurred.

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 exploitation, development and acquisition 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 purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, 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 "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

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 resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- 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 or accidents, such as fires or blowouts;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards, tornados and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;

declines in oil and natural gas prices;
limited availability of financing at acceptable terms;
title problems or legal disputes regarding leasehold rights; and
limitations in the market for oil and natural gas.

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Our identified drilling locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

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 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, depends 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. If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, 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 debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis 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 might be required to dispose of material assets or operations to meet debt service and other obligations. Our Revolving Credit Agreement and the indenture governing our senior unsecured notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

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 indenture governing our senior unsecured notes contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production or interest rates;

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incur liens; and

engage in certain other transactions without the prior consent of the lenders.

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 impose on us.

Our Revolving Credit Agreement limits the amount we can borrow up to the lower of our aggregate lender commitments and a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties securing our loan. 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.

A breach of any covenant in our Revolving Credit Agreement would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the relevant facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

If we are unable to comply with the restrictions and covenants in our Revolving Credit Agreement, there could be an event of default under the terms of our Revolving Credit Agreement, which could result in an acceleration of repayment.

If we are unable to comply with the restrictions and covenants in our Revolving Credit Agreement, there could be an event of default under the terms of this facility. Our ability to comply with these restrictions and covenants, including meeting the financial ratios and tests under our Revolving Credit Agreement, may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or continue to decline, our ability to comply with these covenants may be impaired. We cannot assure 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 our Revolving Credit Agreement, the lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable. 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 our Revolving Credit Agreement or obtain needed waivers on satisfactory terms.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and the Midland-Cushing differential, we enter into commodity derivative contracts for a significant portion of our production, primarily consisting of put spreads and basis swaps. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Our Properties—Sources of Our Revenues” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Our Properties—Realized Prices on the Sale of Oil, Natural Gas and NGLs.” Accordingly, our earnings may fluctuate significantly as a result of changes in

fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise

available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have an adverse effect on our financial condition.

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.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve 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. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Approximately 45% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2015, approximately 45% of our net leasehold acreage was undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established 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.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. At December 31, 2015, 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, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. As an example, since all of our production originates in Midland, Texas, our realizations on sales of our oil production may be affected by the Midland-Cushing price differential, which reflects the difference between the price of crude at Midland, Texas, versus the price of crude at Cushing, Oklahoma, a major hub where production from Midland is often transported via pipeline. The price we currently realize on barrels of oil we sell is reduced by the value of the Midland-Cushing differential, which reached as high as \$21 per barrel in

August 2014. If the Midland-Cushing differential, or other price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

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

The marketing of oil, NGLs and natural gas production depends in large part on the availability, proximity and capacity of 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, or if these systems are unavailable to us, 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 our own facility. 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, NGLs and gas production. Our plans to develop and sell our oil and 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.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production.

The marketing of oil and gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities were unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced 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, refining or processing facilities; 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, notice as to when these circumstances will arise and their duration.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as winter storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or land men 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 do 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.

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 be ultimately developed or produced.

At December 31, 2015, 59% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 72.4 MMBoe of estimated proved undeveloped reserves will require an estimated \$818.4 million 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 capital markets, our Revolving Credit Agreement and derivative contracts. 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 (PUDs) in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they 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 generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration 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 and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire 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 limitations.

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

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

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 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 “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.

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 are subject to all of the operating risks associated with drilling for and producing oil and natural gas. 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, natural resources and equipment;
- pollution and other environmental damage;

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- regulatory investigations and penalties;
- suspension 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 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 cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

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 and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

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

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

We are subject to complex U.S. federal, state, local and other laws and regulations related to environmental, 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 the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and 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 is to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. 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. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. See “Business—Regulation of the Oil and Natural Gas Industry” for a further description of the laws and regulations that affect us.

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

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

A downgrade in our credit ratings could negatively impact our cost of and ability to access capital.

As of December 31, 2015, our long-term debt was rated B3 with a positive outlook by Moody's Investors Service, Inc. ("Moody's"), and B with a stable outlook by Standard & Poor's Ratings Services. On December 16, 2015, Moody's announced that it had placed the ratings of 29 U.S. exploration and production companies and their related subsidiaries on review for downgrade. Since that action, Moody's lowered its oil price estimates and placed additional exploration and production companies and their related subsidiaries, including Parsley LLC, on review for downgrade. With Moody's reduced expectations for the likely range of prices and deteriorating industry conditions, there is an increased possibility for multi-notch downgrades as an outcome of the review process. The ultimate outcome of the ratings review process for any particular exploration and production company will depend on the issuer's particular credit attributes. As of the date of this Annual Report, 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 our costs of capital or our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets and the cost of any new debt could be much higher than our outstanding debt. 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 and natural gas 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. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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 Domenici-Barton Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, 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 FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the Federal Trade Commission 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 million 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 "Business—Regulation of the Oil and Natural Gas Industry."

Climate change laws and regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the oil and natural gas that we produce while 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 an endangerment 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 that will be established on a case-by-case basis. 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 monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Recently, in December 2015, the EPA finalized rules that added new sources to the scope of the greenhouse gases monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. In addition, as noted above, the EPA has proposed an NSPS related to methane emissions from the oil and natural

gas source category as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025. Additional federal action with respect to the control of methane emissions is likely.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. 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. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some 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 and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. 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. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some 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 and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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 in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is a common industry 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, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels, and published permitting guidance in February 2014 addressing the performance of such activities. Also, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Further, the EPA proposed regulations under the CWA in April 2015

prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board. In addition, the U.S. Department of the Interior finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

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 government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. 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 could incur potentially 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.

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.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas 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 remained relatively steady despite the recent downturn in commodity prices. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has continued to be competitive, and would be expected to increase substantially 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 result in oil and gas production volumes being below our forecasted 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.

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

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile commodity prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, 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.

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. For example, in the event that Mr. Sheffield no longer controls the entity that is the sub-operator of the 37 legacy wells that we operate and that we assumed from Parker and Parsley, the sub-operating agreement governing the terms of our arrangement could terminate and we would no longer be the operator of record on these wells. If the sub-operating agreement were to terminate, we would be unable to dictate the pace of development and manage the cost, type, and timing of the drilling program on these identified drilling locations, which could impact our ability to recognize the proved undeveloped reserves associated with these properties.

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 rapid 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 burden;
- increased capital requirements; 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, 2015, we had completed 61 gross (51.9 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. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity prices decline, 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.

Increases in interest rates 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 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. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an “oil fee” of \$10.25 on a per barrel equivalent of crude oil. This fee would be collected

on domestically produced and imported petroleum products. The fee would be phased in evenly over five years, beginning October 1, 2016. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

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

As of December 31, 2015, we had approximately \$50.4 million of U.S. federal net operating loss carryforwards (“NOLs”). Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. Our NOLs begin to expire in 2033. 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 shareholders (or groups of shareholders) 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. Any unused annual limitation may be carried over to later years. We may be found to have had an ownership change in 2015, which would result in an annual limitation under Section 382. However, even if we did have an ownership change in 2015, we do not believe that such 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 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

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

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

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. However, Texas has endured severe drought conditions over the past several years. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations from local sources, we may be unable to produce oil and natural gas economically, which could have an adverse effect on our financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities 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. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

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

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). To date, the CFTC has only designated certain interest rate swaps and credit default swaps for application of such mandatory clearing and trade-execution requirements. Although we expect to qualify for the end-user exception from such requirements for swaps entered 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 our swaps do not qualify for the commercial end-user exception, or if the cost of entering into swaps outside of mandatory clearing becomes prohibitive, we may be required to clear such transactions. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for swaps outside of mandatory clearing. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such 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, the posting of collateral could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives, 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 derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, 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. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

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 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, facilities and infrastructure may result in increased capital and operating costs. 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 or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and

systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability.

Risks Related to our Class A Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we are required to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are required to:

- institute a more comprehensive compliance function;
 - comply with rules promulgated by the NYSE;

- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

- establish new internal policies, such as those relating to insider trading; and

- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, as a public company subject to these rules and regulations, it can be more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

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 distributions to its unitholders, including us, in an amount sufficient to cover all applicable taxes at assumed tax rates and payments under the TRA, and 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 credit facilities. 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 principal stockholders will collectively hold a substantial majority of the voting power of our common stock.

Holders of Class A Common Stock and Class B Common Stock will 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. Our executive officers hold approximately 27.1% of our ownership interest and is our largest stockholder group. The existence of significant stockholders may also 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 our management team continues to control a significant amount 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 own best interests. In any of these matters, the interests of our management team may differ or conflict with the interests of our other stockholders. In addition, NGP and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. NGP and its affiliates may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Moreover, this concentration of stock ownership may also adversely affect

the trading price of our Class A Common Stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

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."

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Class A Common Stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

In addition, certain change of control events have the effect of accelerating the payment due under our TRA, 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 amended and restated 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 amended and restated 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 (the "DGCL"), our amended and restated 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. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our amended and restated certificate of incorporation described in the preceding sentence. 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 amended and restated 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, and our credit facilities 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 do not plan to declare dividends on shares of our Class A Common Stock in the foreseeable future. Additionally, our credit facilities place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on

your investment in us will be if you sell your Class A Common Stock at a price greater than you paid for it. There is no guarantee that the price of our Class A Common Stock that will prevail in the market will ever exceed the price at which you purchased your shares of Class A Common Stock.

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

The TRA 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 as a result of (i) any tax basis increases resulting from the contribution in connection with the IPO by such TRA Holder of all or a portion of its PE Units to Parsley Inc. 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. In addition, 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 payment obligations under the TRA are our obligations and not obligations of Parsley LLC. 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 term of the TRA will continue until all such tax benefits have been utilized or expired, unless we exercise our right to terminate the TRA by making the termination payment specified in the agreement.

The actual increase in tax basis, as well as the amount and timing of any payments under the TRA, will vary depending upon a number of factors, 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 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 depletable, depreciable or amortizable basis. We expect that the payments that we will be required to make under the TRA could be substantial.

The payments under the TRA will not be conditioned upon a holder of rights under the TRA having a continued ownership interest in us. See “Item 13. Certain Relationships and Related Transactions, and Director Independence.”

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 elect to terminate the TRA early or it is terminated early due to certain mergers or other changes of control or due to a material breach of the TRA, we would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the TRA. The calculation of anticipated future tax benefits will be based upon certain assumptions as set forth in the TRA, including the assumption that we have sufficient taxable income to fully utilize such benefits and that any PE Units that the PE Unit 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 the actual realization, if any, of such future benefits.

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 cost a potential acquirer may attribute to satisfying such obligations. For example, if the TRA were terminated at December 31, 2015, the estimated termination payment would be approximately \$193.8 million (calculated using a discount rate equal to the LIBOR, plus 300 basis points,

applied against an undiscounted liability of \$409.0 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.

Payments under the TRA will be based on the tax reporting positions that we will determine. The holders of rights under the TRA will not reimburse us for any payments previously made under the TRA if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any such holder will be netted against payments otherwise to 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.

We may issue preferred stock whose terms could adversely affect the voting power or value of our Class A Common Stock.

Our amended and restated 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 Class A 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 Class A 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 Class A 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.

As of December 31, 2015, we are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act. Section 404 requires that we document and test our internal control over financial reporting and issue 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, 2015, our acreage position consisted of 110,967 net acres, 84,441 of which are in the Midland Basin and 26,526 of which are in the Delaware Basin, approximately 55% of which is held by production. As of December 31, 2015, we have interests in 667 gross (431 net) producing wells, of which we operate 99.5%. The table below sets forth our identified drilling locations in the Midland Basin as of December 31, 2015.

Target Horizontal Zone	Target Horizontal Locations					
	Core (1)		Tier I (1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Spraberry (2)	254	197	77	57	331	254
Wolfcamp A	323	268	118	93	441	361
Wolfcamp B	314	269	146	118	460	387
Wolfcamp C	366	306	133	105	499	411
Upper Pennsylvanian (Cline)	402	332	133	105	535	437
Lower Pennsylvanian (Atoka)	320	271	91	72	411	343
Total Target Horizontal Location	1,979	1,643	698	550	2,677	2,193

(1) Our target horizontal location count implies 660' to 990' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

(2) Spraberry locations are based on Middle and Upper Spraberry. For the Middle Spraberry, only those locations located in Upton County are included at 990' spacing.

The Permian Basin is an area that extends through multiple counties in Southeast New Mexico and West Texas and covers an area some 250 miles wide and 300 miles long. It is comprised of three main sub-areas, the Delaware Basin, the Central Basin Platform and the Midland Basin. The Permian Basin is characterized by oil and liquids rich gas production. According to the RRC, over 29 billion barrels of oil and 75 trillion cubic feet of gas have been produced in the Permian Basin since the first producing well was drilled in 1921 in Mitchell County. 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 formations. With the advent of horizontal drilling and the application of multi-stage fracture treatments within one horizontal well bore, activity has increased drastically targeting one unconventional formation at a time for production.

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 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 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 formation

throughout the Permian Basin. In the later Permian time 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 in 1949. The field stretches over 150 miles North to South and over 75 miles East to West. According to the RRC, over 1.3 billion barrels of oil and 3.9 trillion cubic feet of gas have been produced in this field through December 2014. Additionally, activity targeting the deeper Wolfcamp formation increased dramatically after Henry Petroleum started drilling fully through the Wolfcamp formation 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 formations. Concurrently, operators started testing zones singularly with horizontal wells and multi-stage treatments. To date, the majority of these wells in the Midland Basin target the Upper Pennsylvanian and Wolfcamp formations. There have also been successful horizontal tests in the Clearfork, Spraberry, and Atoka formations.

Core Area Descriptions

We group our assets by area based on similar geologic, economic and technical requirements. We split our assets into four areas, the Midland Basin-Core, Midland Basin-Tier I, Midland Basin-Other and Southern Delaware Basin.

Midland Basin-Core

Our Midland Basin-Core assets are characterized by being in the modern day sedimentary deep portion of the Midland Basin resulting in multiple stacked pay benches ranging from the Clearfork to the Atoka formations. Generally, well drilling and completion costs are slightly higher in the Midland Basin-Core area due to design for deeper depths and higher pressures. Our Midland Basin-Core contains the areas of Andrews, Glasscock, Howard, Martin, Midland, Reagan and Upton Counties.

As of December 31, 2015, we have 86,886 gross (59,895 net) acres in our Midland Basin-Core area. Approximately 78% of our acreage in this area is held by production. We have interests in 57 gross (47.3 net) producing horizontal wells and 472 gross (295.4 net) producing vertical wells in our Midland Basin-Core area as of December 31, 2015 and we operate 100% of the wells in which we have an interest. The table below sets forth our identified drilling locations in the Midland Basin-Core as of December 31, 2015.

Target Horizontal Zone	Total (1,2)	
	Gross	Net
Spraberry (3)	254	197
Wolfcamp A	323	268
Wolfcamp B	314	269
Wolfcamp C	366	306
Upper Pennsylvanian (Cline)	402	332
Lower Pennsylvanian (Atoka)	320	271
Total Target Horizontal Location	1,979	1,643

(1) Our target horizontal location count implies 660' to 990' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

(2) Average Core Stimulated Length is estimated at 6,215 ft.

(3) Spraberry locations are based on Middle and Upper Spraberry. For the Middle Spraberry, only those locations located in Upton County are included at 990' spacing.

Midland Basin-Tier I

Our Midland Basin-Tier I assets are characterized by being in a shallower modern day sedimentary portion of the Midland Basin than our Midland Basin-Core. The southern boundary is the Big Lake Fault, the western boundary is the Central Basin Platform, the northern boundary is the Horseshoe Atoll and the Eastern boundary is the transition to the Eastern Shelf. Due to lower pressures and shallower depths, well drilling and completion costs tend to be slightly lower than the Midland Basin-Core. Our Midland Basin-Tier I includes areas of Andrews, Borden, Crane, Dawson, Ector, Glasscock, Howard, Irion, Martin, Midland, Reagan and Upton Counties.

As of December 31, 2015, we have 22,061 gross (17,227 net) acres in our Midland Basin-Tier I area. Approximately 57% of our acreage in this area is held by production. We have interests in 10 gross (9.4 net) producing horizontal wells and 111 gross (73.6 net) producing vertical wells in our Midland Basin-Tier I area as of December 31, 2015 and operate 98%, of the wells in which we have an interest.

The table below sets forth our identified drilling locations in the Midland Basin-Tier I as of December 31, 2015.

	Total (1,2) GrossNet	
Target Horizontal Zone		
Spraberry	77	57
Wolfcamp A	118	93
Wolfcamp B	146	118
Wolfcamp C	133	105
Upper Pennsylvanian (Cline)	133	105
Lower Pennsylvanian (Atoka)	91	72
Total Target Horizontal Location	698	550

(1) Our target horizontal location count implies 660' to 870' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

(2) Average Tier 1 Stimulated Length is estimated at 5,235 ft.

Midland Basin-Other

Our Midland Basin-Other assets are characterized as assets that we have limited operating activity in which still fall within the Midland Basin. Over time, as our operating results dictate, we may reclassify these areas based on geologic, economic and technical results. Our Midland Basin-Other includes certain portions of Andrews, Gaines, Reagan, Upton, Irion, Martin, Glasscock, and Howard Counties.

As of December 31, 2015, we have 9,875 gross (7,318 net) undeveloped acres in our Midland Basin-Other area. None of our acreage in this area is held by production. We have interests in nine gross (0.9 net) producing non-operated wells in our Midland Basin-Other area as of December 31, 2015.

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, 2015, our Delaware Basin acreage includes 747 MBoe of proved developed reserves and 3.2 MMBoe of proved undeveloped reserves. Our Delaware Basin acreage also includes four gross (1.5 net) producing horizontal wells and four gross (three net) producing vertical wells. We hold a leasehold position in 28,912 gross (26,526 net) acres in the Delaware Basin which we call our Trees Ranch Prospect.

Production Status

For the year ended December 31, 2015, our average daily net sales from production from our horizontal wells on our Midland Basin acreage, was 11,052 Boe/d, of which 76% was from oil, 11% was from natural gas, and 13% was from NGLs.

Facilities

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

Recent Activity

During the year ended December 31, 2015, we completed 41 gross (37.4 net) horizontal wells for an aggregate net cost of \$261.6 million and 16 gross (14.7 net) vertical wells were completed on our Midland Basin acreage for an aggregate estimated net cost of \$33.7 million.

As of December 31, 2015, we have identified 2,677 potential horizontal drilling locations and 147 80- and 40-acre potential vertical drilling locations on our existing acreage, which does not include any locations in our Southern Delaware acreage. Our target horizontal location count implies 660' to 990' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

Production and Price History

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

	Year ended December 31, 2015 2014 2013 (in thousands, except per share unit data)		
Average daily production volume (1):			
Oil (Bbls/d)	13,170	7,778	2,874
Natural gas (Mcf/d)	28,326	19,849	12,822
Natural gas liquids (Boe/d)	4,110	3,123	—
Total (Boe/d)	22,003	14,207	5,011
Average realized prices:			
Oil sales, without realized derivatives (per Bbls)	\$44.89	\$81.91	\$93.28
Oil sales, with realized derivatives (per Bbls)	56.60	81.33	87.91
Natural gas, without realized derivatives (per Mcf)	2.57	4.23	4.95
Natural gas, with realized derivatives (per Mcf)	2.72	4.32	4.95
NGLs sales (per Bbls)	15.79	33.83	—
Average price per Boe, without realized derivatives	33.13	58.19	66.17
Average price per Boe, with realized derivatives	40.33	58.00	63.09
Expense per Boe:			
Lease operating expenses	\$7.83	\$7.34	\$9.06
Production and ad valorem taxes	2.22	3.65	3.87
Depreciation, depletion and amortization	22.20	18.18	15.39
General and administrative expenses	6.89	16.96	9.05
Exploration costs	1.73	0.39	—
Impairment	0.12	—	—
Acquisition costs	—	0.49	—
Accretion of asset retirement obligations	0.10	0.10	0.10

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Rig termination costs	1.12	0.15	—
Other operating expenses	0.21	—	—
Total operating expenses	\$42.42	\$47.26	\$37.47

(1) For the year ended December 31, 2013, NGLs sales and production are included in the natural gas line item.

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Proved Reserves

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates as of December 31, 2015 and 2014 were prepared based on reports by NSAI. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 19, 2016, filed as an exhibit to this Annual Report, was Mr. James Ball. Mr. Ball, Vice President at NSAI and a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1998 and has over 18 years of prior industry experience.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Matthew Gallagher, our Vice President—Chief Operating Officer, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Gallagher is a petroleum engineer with approximately 11 years of reservoir and operations experience, and our engineering and geoscience staff have an average of approximately 13 years of industry experience per person.

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

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by Mr. Gallagher or under his direct supervision;
- verification of property ownership by our land department.

Estimation of Proved Reserves. Under SEC rules, proved reserves are 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2015 and December 31, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. The current pricing environment could impact future economics.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with

consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Summary of Oil, NGLs, and Natural Gas Reserves. The following table presents our estimated net proved oil, NGLs, and natural gas reserves as of the periods indicated:

	December 31,	
	2015	2014
Proved developed reserves:		
Oil (MBbls)	27,628	23,547
NGLs (MBbls)	10,890	11,491
Natural gas (MMcf)	77,612	65,484
Combined (MBoe)(1)	51,454	45,952
Proved undeveloped reserves:		
Oil (MBbls)	46,249	24,070
NGLs (MBbls)	12,848	11,175
Natural gas (MMcf)	79,563	58,161
Combined (MBoe)(1)	72,358	44,939
Proved reserves:		
Oil (MBbls)	73,877	47,617
NGLs (MBbls)	23,738	22,667
Natural gas (MMcf)	157,175	123,645
Combined (MBoe)(1)	123,811	90,891

(1) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency.

This is an energy content correlation and does not reflect a value or price relationship between the commodities. Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Item 1A. Risk Factors."

Additional information regarding our proved reserves can be found in the notes to our consolidated and combined financial statements included elsewhere in this Annual Report and the proved reserve report as of December 31, 2015, which is included as an exhibit to this Annual Report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, our proved undeveloped reserves were composed of 46,249 MBbls of oil, 79,563 MMcf of natural gas, and 12,848 MBbls of NGLs, for a total of 72,358 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during the year ended December 31, 2015 (in MBoe):

Balance, December 31, 2014	44,939
Purchases of reserves	3,375
Extensions and discoveries	38,330
Revisions of previous estimates	(13,577)
Transfers to proved developed	(709)
Balance, December 31, 2015	72,358

Extensions and discoveries of 38,330 MBoe during the year ended December 31, 2015, resulted primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year.

Costs incurred relating to the development of locations that were classified as PUDs at December 31, 2014 were \$40.2 million during the year ended December 31, 2015. Additionally, during 2015 we spent approximately \$345.1 million drilling and completing other in-field wells which were not classified as PUDs as of December 31, 2014. Estimated future development costs relating to the development of PUDs at December 31, 2015 were projected to be approximately \$105.1 million in the year ended December 31, 2016, \$245.8 million in 2017, \$268.4 million in 2018, \$150.0 million in 2019, and \$43.1 million in future periods. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking.

As of December 31, 2015, none of our total proved reserves were classified as proved developed non-producing.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2015 relating to our leasehold acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the applicable leases. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

As of December 31, 2015

Area	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Midland Basin	76,585	53,670	37,237	30,771	113,822	84,441
Delaware Basin	1,972	1,778	26,940	24,748	28,912	26,526
Total	78,557	55,448	64,177	55,519	142,734	110,967

- (1) Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.
- (2) Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.
- (3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.
- (4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. All of the leases governing our acreage

have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 60 to 180 days of the expiration date, without the requirement of a lease extension payment. Thereafter, the lease is held with additional development every 60 to 180 days until the entire lease is held by production. None of our vertical drilling locations associated with proved undeveloped reserves are scheduled for drilling outside of a lease term that is not accounted for with a continuous development schedule. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2015, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates. There are currently no expirations for the year ended December 31, 2020.

	2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	22,764	18,346	5,624	4,931	7,404	6,570	1,446	923
Delaware Basin	1,760	693	—	—	16,329	16,089	8,852	7,966
Total	24,524	19,039	5,624	4,931	23,733	22,659	10,298	8,889

Drilling Results

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

	Year ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Horizontal:						
Development Wells:						
Productive(1)	41	36	20	15	—	—
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive(1)	1	1	—	—	—	—
Dry holes	—	—	—	—	—	—
Vertical:						
Development Wells:						
Productive(1)	15	14	168	137	170	100
Dry holes	—	—	—	—	1	1
Exploratory Wells:						
Productive(1)	1	1	2	2	—	—
Dry holes	—	—	—	—	—	—
Total:						
Productive(1)	58	52	190	154	170	100
Dry holes	—	—	—	—	1	1
	58	52	190	154	171	101

(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 where there is no production history.

As of December 31, 2015 we had five gross (five net) horizontal wells in the process of drilling, one gross (one net) horizontal well awaiting hydraulic fracturing procedures, and seven gross (6.6 net) horizontal wells in the process of being completed that are not reflected in the above table.

Title to Properties

As is customary in the oil and natural gas industry, when we acquire leasehold acreage, we conduct title due diligence on the subject properties but may not have title opinions covering the properties prior to entering into a purchase and

sale agreement. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations completed after the closing of an acquisition reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Facilities

As of December 31, 2015, we leased corporate office space in Austin, Texas at 303 Colorado St., where our corporate headquarters is located. We also lease corporate office space and own field operation facilities in Midland, Texas. We believe that our facilities are adequate for our current operations.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment-related disputes. We do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our Class A Common Stock began trading on the NYSE under the symbol "PE" on May 29, 2014. Prior to that, there was no public market for our Class A Common Stock. The following table sets forth high and low sales prices of our Class A Common Stock for the periods indicated:

	High	Low
2014		
Quarter ended December 31	\$21.03	\$11.26
Quarter ended September 30	\$23.95	\$19.89
Quarter ended June 30 (a)	\$25.16	\$22.11
2015		
Quarter ended December 31	\$19.82	\$15.29
Quarter ended September 30	\$17.42	\$13.72
Quarter ended June 30	\$18.87	\$15.92
Quarter ended March 31	\$18.29	\$13.50

(a) Represents the period from May 29, 2014, the date on which our Class A Common Stock began trading on the NYSE, through June 30, 2014.

On February 26, 2016, the closing sales price of our Class A Common Stock as reported by the NYSE was \$18.00 per share and we had approximately 30 holders of record of our Class A Common Stock. This number does not include owners for whom shares of our Class A Common Stock may be held in "street" name.

There is no public market for our Class B Common Stock. On February 26, 2016, we had approximately 11 holders of record of our Class B Common Stock.

Dividends

We have never declared or paid any cash 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 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. In addition, our debt agreements restrict our ability to pay cash dividends to holders of our Class A Common Stock or Class B Common Stock.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

We did not purchase any shares of our Class A Common Stock during the quarter ended December 31, 2015.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2015, except as set forth in our Quarterly Reports on Form 10-Q or Current Reports on Form 8-K filed during such fiscal year.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected historical financial data for the periods and as of the periods indicated. The following selected consolidated and combined financial and operating data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data”:

	Year ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share unit data)				
REVENUES					
Oil sales	\$215,795	\$232,554	\$97,839	\$30,443	\$8,702
Natural gas sales	26,582	30,642	23,179	7,236	2,132
Natural gas liquids sales	23,680	38,561	—	—	—
Total revenues	266,057	301,757	121,018	37,679	10,834
OPERATING EXPENSES					
Lease operating expenses	62,913	38,071	16,572	4,646	1,446
Production and ad valorem taxes	17,800	18,941	7,081	2,412	610
Depreciation, depletion and amortization	178,281	94,297	28,152	6,406	1,247
General and administrative expenses	55,294	87,949	16,553	3,658	1,369
Exploration costs	13,865	3,136	—	—	—
Impairment	950	—	—	—	—
Acquisition costs	—	2,527	—	—	—
Accretion of asset retirement obligations	826	512	181	66	32
Rig termination costs	8,970	765	—	—	—
Other operating expenses	1,696	—	—	—	—
Total operating expenses	340,595	246,198	68,539	17,188	4,704
OPERATING (LOSS) INCOME	(74,538)	55,559	52,479	20,491	6,130
OTHER INCOME (EXPENSE)					
Interest expense, net	(45,581)	(39,624)	(13,733)	(6,295)	(461)
(Loss) gain on sale of property	(34,374)	(2,097)	36	7,819	6,638
Prepayment premium on extinguishment of debt	—	(5,107)	—	(6,597)	—
Derivative income (loss)	60,818	83,858	(9,800)	(2,190)	(255)
Other income (expense)	(3,111)	601	434	225	(116)
Total other income (expense), net	(22,248)	37,631	(23,063)	(7,038)	5,806
(LOSS) INCOME BEFORE INCOME TAXES	(96,786)	93,190	29,416	13,453	11,936
INCOME TAX BENEFIT (EXPENSE) (2)	23,755	(36,468)	(1,906)	(554)	(116)
NET (LOSS) INCOME	(73,031)	56,722	27,510	12,899	11,820
LESS: NET LOSS (INCOME) ATTRIBUTABLE TO					
NONCONTROLLING INTERESTS	22,547	(33,293)	—	—	—
NET (LOSS) INCOME ATTRIBUTABLE TO					
PARSLEY ENERGY INC. STOCKHOLDERS	\$(50,484)	\$23,429	\$27,510	\$12,899	\$11,820
Net (loss) income per common share: (1)					
Basic	\$(0.45)	\$0.65			
Diluted	\$(0.45)	\$0.65			
Weighted average common shares outstanding: (1)					

Basic	111,271	93,168
Diluted	111,271	93,271

- (1) Please see the section entitled Revision of 2014 Financial Statements in Note 2—Summary of Significant Accounting Policies and Note 8—Equity in our consolidated and combined financial statements, included herein, for additional discussion.
- (2) Parsley Energy, Inc. is a subchapter C corporation (“C-Corp”) under the Internal Revenue Code of 1986, as amended, and is subject to federal and State of Texas income taxes. Our predecessor, Parsley LLC was not subject to U.S. federal income taxes. As a result, the consolidated and combined net income in our historical financial statements for periods prior to our May 29, 2014 IPO does not reflect the tax expense we would have incurred as a C-Corp during such periods.

	Year ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share unit data)				
Total Production Volumes					
Oil (MBbls)	4,807	2,839	1,049	356	94
Natural gas (MMcf)	10,339	7,245	4,680	1,493	304
Natural gas liquids (MBoe)	1,500	1,140	—	—	—
Combined (MBoe)	8,031	5,186	1,829	604	145
Average daily production volume:					
Oil (Bbls/d)	13,170	7,778	2,874	972	258
Natural gas (Mcf/d)	28,326	19,849	12,822	4,079	832
Natural gas liquids (Boe/d)	4,110	3,123	—	—	—
Total (Boe/d)	22,003	14,207	5,011	1,652	397
Average realized prices:					
Oil sales, without realized derivatives (per Bbls)	\$44.89	\$81.91	\$93.28	\$85.60	\$92.43
Oil sales, with realized derivatives (per Bbls)	56.60	81.33	87.91	83.08	92.17
Natural gas, without realized derivatives (per Mcf)	2.57	4.23	4.95	4.85	7.02
Natural gas, with realized derivatives (per Mcf)	2.72	4.32	4.95	4.85	7.02
NGLs sales (per Boe)	15.79	33.83	—	—	—
Average price per Boe, without realized derivatives	33.13	58.19	66.17	62.33	74.84
Average price per Boe, with realized derivatives	40.33	58.00	63.09	60.85	74.67
Expense per Boe:					
Lease operating expenses	\$7.83	\$7.34	\$9.06	\$7.69	\$9.99
Production and ad valorem taxes	2.22	3.65	3.87	3.99	4.21
Depreciation, depletion and amortization	22.20	18.18	15.39	10.60	8.61
General and administrative expenses	6.89	16.96	9.05	6.00	9.37
Exploration costs	1.73	0.39	—	—	—
Impairment	0.12	—	—	—	—
Acquisition costs	—	0.49	—	—	—
Accretion of asset retirement obligations	0.10	0.10	0.10	0.11	0.22
Rig termination costs	1.12	0.15	—	—	—
Other operating expenses	0.21	—	—	—	—
Total operating expenses per Boe	\$42.42	\$47.26	\$37.47	\$28.39	\$32.40
Consolidated and Combined Statements of Cash Flows					
Data:					
Net cash provided by (used in):					
Operating activities	\$172,290	\$184,983	\$53,235	\$5,025	\$16,031
Investing activities	(427,165)	(1,247,677)	(425,611)	(89,539)	(15,654)
Financing activities	547,409	1,093,851	378,096	74,245	19,729
Proved reserves:					
Oil (MBbls)	73,877	47,617	29,507	12,987	8,519
Natural gas (MMcf)	23,738	22,667	77,818	30,214	20,689
NGLs (MBbls)	157,175	123,645	12,357	4,732	3,127
Combined (MBoe)	123,811	90,891	54,834	22,755	15,094
Consolidated and Combined Balance Sheet Data:					
Cash and cash equivalents	\$343,084	\$50,550	\$19,393	\$13,673	\$23,942

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Total assets	2,514,192	2,051,079	742,556	181,239	64,478
Long-term debt	555,924	676,845	429,970	119,663	26,118
Total equity	1,586,641	992,489	108,032	6,017	9,053
Other Financial Data:					
Adjusted EBITDAX (1)	195,386	207,077	76,828	26,281	7,265

(1) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measures calculated and presented in accordance with GAAP, please read “— Non-GAAP Financial Measures.”

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Non-GAAP Financial Measures

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income as determined by GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated and combined financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net (loss) income before depreciation, depletion, and amortization ("DD&A"), exploration costs, impairment, acquisition costs, loss (gain) on sales of oil and natural gas properties, asset retirement obligation accretion expense, stock based compensation, net interest expense, income tax (benefit) expense, rig termination, prepayment premium on extinguishment of debt, inventory write down, (income) loss on derivative instruments, net settlements on derivative instruments, and premium realization on options that settled during the period.

Management believes Adjusted EBITDAX is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income for each of the periods indicated.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Adjusted EBITDAX reconciliation to net income:					
Net (loss) income attributable to Parsley Energy, Inc. stockholders'	\$(50,484)	\$23,429	\$27,510	\$12,899	\$11,820
Net (loss) income attributable to noncontrolling interests	(22,547)	33,293	—	—	—
Depreciation, depletion and amortization	178,281	94,297	28,152	6,406	1,247
Exploration costs	13,865	3,136	—	—	—
Impairment	950	—	—	—	—
Acquisition costs	—	2,527	—	—	—
Loss (gain) on sales of oil and natural gas properties	34,374	2,097	(36)	(7,819)	(6,638)
Asset retirement obligation accretion expense	826	512	181	66	32
Non-cash stock based compensation	8,133	53,297	1,233	—	—
Interest expense, net	45,581	39,624	13,733	6,295	461
Income tax (benefit) expense	(23,755)	36,468	1,906	554	116
Rig termination	8,970	765	—	—	—
Prepayment premium on extinguishment of debt	—	5,107	—	6,597	—

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Inventory write down	4,147	—	—	—	—
Derivative (income) loss	(60,818)	(83,858)	9,800	2,190	255
Net settlements on derivative instruments	46,457	3,311	(198)	179	78
Premium realization on options that settled during the period	11,406	(6,928)	(5,434)	(1,076)	(103)
Adjusted EBITDAX	\$195,386	\$207,077	\$76,847	\$26,291	\$7,268

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PV-10

The following table provides a reconciliation of PV-10 to the GAAP financial measure of Standardized Measure as of December 31, 2015:

	As of December 31, 2015 (in millions)
PV-10 of proved reserves	\$ 697.3
Present value of future income tax discounted at 10%	(99.5)
Standardized Measure	\$ 597.8

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

The following discussion and analysis should be read in conjunction with our consolidated and combined financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Item 1A. Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Our Predecessor and Parsley Energy, Inc.

Parsley Energy, Inc. was formed in December 2013. For purposes of this discussion, our accounting predecessors are Parsley Energy, LLC ("Parsley LLC") and its predecessors, Parsley Energy Operations, LLC ("Operations") and Parsley Energy, L.P. ("Parsley LP"). Both Operations and Parsley LP began operations in 2008 in conjunction with the acquisition of operator rights to wells producing from the Spraberry Trend in the Midland Basin. Parsley LLC was formed in June 2013 to engage in the acquisition, development and exploitation of unconventional oil and natural gas reserves located in the Permian Basin. Concurrent with the formation of Parsley LLC, all of the interest holders in Parsley LP, Parsley Energy Management, LLC, and Operations exchanged their interests in each such entity for interests in Parsley LLC (the "Exchange"). The Exchange was treated as a reorganization of entities under common control.

We are a holding company whose sole material asset consists of PE Units. We are the managing member of Parsley LLC and are responsible for all operational, management and administrative decisions of Parsley LLC, and we consolidate the financial results of Parsley LLC and its subsidiaries.

Basis of Presentation

We consider and report all of our operations as one segment.

Overview

We are an independent oil and natural gas company focused on the acquisition, development and exploitation of unconventional oil and natural gas reserves in the Permian Basin. Our properties are located in the Midland and Delaware Basins and our activities have historically been focused on the vertical development of the Spraberry, Wolfberry and Wolfboka Trends of the Midland Basin. Our vertical wells in the area are drilled into stacked pay zones that include the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline), Strawn, Atoka and Mississippian formations. We now focus predominately on horizontal development drilling and expect to target various stacked pay intervals in the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline) and Atoka shales.

Our Properties

At December 31, 2015, our acreage position was 142,734 gross (110,967 net) acres. The majority of our acreage is located in the Midland Basin, and the majority of our identified horizontal drilling locations are located in our

horizontal focus area, which is comprised of specific portions of Upton, Reagan, Midland, and Glasscock Counties in Texas. As of December 31, 2015, we operated 651 vertical wells across our acreage in the Midland Basin. Since commencing our horizontal drilling program in 2013 through December 31, 2015, we have drilled and completed 60 gross (51.0 net) horizontal wells in the Midland Basin, of which 41 gross (36.0 net) were completed during 2015. We have also drilled and completed one gross (0.9 net) horizontal wells in the Delaware Basin. As of December 31, 2015, we operated 68 gross (57.6 net) horizontal wells. Additionally, we commenced our vertical appraisal drilling program in the Delaware Basin during the first quarter of 2014. As of December 31, 2015, we had drilled and completed three vertical appraisal wells and one horizontal appraisal well in the Delaware Basin. As of December 31, 2015, we have identified 2,677 potential horizontal drilling locations and 147 80- and 40-acre potential vertical drilling locations on our existing acreage, which does not include any locations in our Southern Delaware Basin acreage. As of December 31, 2015, we had interests in 667 gross (431 net) producing wells across our properties and operated 99.5% of the wells in which we had an interest.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures; and
- Adjusted EBITDAX.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil, natural gas, and NGLs revenues do not include the effects of derivatives. For the years ended December 31, 2015, 2014 and 2013, our revenues were derived 81%, 77% and 81%, respectively, from oil sales; 10%, 10% and 19%, respectively, from natural gas sales; and 9% and 13% , respectively for 2015 and 2014, from NGLs sales. For the year ended December 31, 2013, NGLs sales were included in the natural gas line item. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Production Volumes

The following table presents historical production volumes for our properties for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
Oil (MBbls)	4,807	2,839	1,049
Natural gas (MMcf)	10,339	7,245	4,680
Natural gas liquids (MBoe) (1)	1,500	1,140	—
Total (MBoe)	8,031	5,186	1,829
Average net production (Boe/d)	22,003	14,207	5,011

(1) For the year ended December 31, 2013, NGLs production was not separately reported.

Production Volumes Directly Impact Our Results of Operations

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic drill-bit growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry and Our Business” for a discussion of these and other risks affecting our proved reserves and production.

Realized Prices on the Sale of Oil, Natural Gas and NGLs

The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the Cushing, Oklahoma transport hub and the Gulf Coast refineries. Periodically, logistical and infrastructure constraints at the Cushing, Oklahoma transport hub have resulted in an oversupply of crude oil at Midland, Texas and thus lower prices for Midland WTI. These lower prices have adversely affected the prices we realize on oil sales and increased our differential to NYMEX WTI.

The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in

transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas, and NGLs normally sell at a discount to the NYMEX WTI and NYMEX Henry Hub price.

	Year Ended December 31,		
	2015	2014	2013
Oil			
NYMEX WTI High	\$61.43	\$107.26	\$110.53
NYMEX WTI Low	\$34.73	\$53.27	\$86.68
Differential to Average NYMEX WTI	\$(3.19)	\$1.65	\$(5.33)
Natural Gas			
NYMEX Henry Hub High	\$3.23	\$6.15	\$4.46
NYMEX Henry Hub Low	\$1.76	\$2.89	\$3.11
Differential to Average NYMEX Henry Hub	\$0.07	\$(0.29)	\$1.16
NGLs			
NYMEX WTI High	\$61.43	\$107.26	\$110.53
NYMEX WTI Low	\$34.73	\$53.27	\$86.68
Differential to Average NYMEX WTI	\$(32.29)	\$(46.44)	\$(98.61)

Historically, oil, natural gas, and NGLs prices have been extremely volatile as illustrated above; we expect the volatility to continue given current economic conditions. To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil production. By removing a significant portion of price volatility associated with our oil production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will sustain gains to the extent our derivatives contract prices are higher than market prices. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We are not under an obligation to hedge a specific portion of our oil or natural gas production.

Our positions hedging production as of December 31, 2015 were as follows:

Description and Production Period (Bbls)	VOLUME	SHORT	LONG	DIFFERENTIAL
		PUT	PUT	
		PRICE	PRICE	PRICE
		(\$/Bbl)	(\$/Bbl)	
Crude Oil Put Spreads:				
Jan 2016 - Feb 2016	70,000	\$ 35.00	\$ 60.00	
Jan 2016 - Feb 2016	240,000	\$ 30.00	\$ 45.00	
Jan 2016 - Feb 2016	240,000	\$ 30.00	\$ 50.00	
Jan 2016 - Feb 2016	240,000	\$ 55.00	\$ 40.00	
Jan 2016 - Mar 2016	585,000	\$ 30.00	\$ 45.00	
Jan 2016 - Jun 2016	300,000	\$ 35.00	\$ 60.00	
Jan 2016 - Dec 2016	1,500,000	\$ 35.00	\$ 50.00	
Mar 2016 - Jun 2016	700,000	\$ 30.00	\$ 40.00	
Apr 2016 - Jun 2016	585,000	\$ 30.00	\$ 40.00	
Jun 2016 - Dec 2016	525,000	\$ 35.00	\$ 50.00	
Jul 2016 - Sept 2016	75,000	\$ 40.00	\$ 55.00	
Jul 2016 - Dec 2016	2,460,000	\$ 40.00	\$ 55.00	
Aug 2016 - Dec 2016	250,000	\$ 35.00	\$ 50.00	
Oct 2016 - Dec 2016	180,000	\$ 40.00	\$ 55.00	
Jan 2017 - Jun 2017	900,000	\$ 40.00	\$ 55.00	
Jan 2017 - Jun 2017	1,434,000	\$ 37.50	\$ 52.50	
Crude Oil Basis Swaps:				
Jul 2016 - Dec 2016	210,000			\$ (1.40)
Jul 2016 - Dec 2016	180,000			\$ (1.35)
Jan 2017 - Dec 2017	600,000			\$ (1.70)
Jan 2017 - Dec 2017	360,000			\$ (1.60)
Jul 2017 - Dec 2017	180,000			\$ (1.65)
Jul 2016 - Dec 2016	368,000			\$ (0.35)
Jul 2016 - Dec 2016	390,000			\$ (1.40)
Jan 2017 - Dec 2017	960,000			\$ (1.65)
Jan 2017 - Dec 2017	1,095,000			\$ (0.40)
Jul 2016 - Dec 2016	368,000			\$ (0.30)
Jan 2017 - Dec 2017	1,095,000			\$ (0.45)

We will recognize the following income (expense) in the line item Derivative income (loss) on our consolidated and combined statements of operations from net cash premiums (paid) received on options that settled during the following periods:

Q1 2016 \$7,828
Q2 2016 \$7,768
Q3 2016 \$(2,754)
Q4 2016 \$(2,982)

Q1 2017 \$(505)
Q2 2017 \$(505)
Q3 2017 \$(1,238)
Q4 2017 \$(1,238)

Principal Components of Our Cost Structure

Lease Operating Expenses. Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water injection and disposal, utilities, materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative expenses or production or ad valorem taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased lease operating expenses in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water

increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

Depletion, Depreciation and Amortization. DD&A is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, which are then allocated to each unit of production using the unit of production method. Please read “—Critical Accounting Policies and Estimates—Successful Efforts Method of Accounting for Oil and Natural Gas Activities” for further discussion.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, amortization and impairment of unproved leasehold costs, and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

General and Administrative Expenses. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations including numerous software applications, audit and other fees for professional services and legal compliance. Also included in general and administrative expenses is compensation expense incurred as a result of our corporate reorganization and IPO and stock based compensation. See “—Factors Affecting the Comparability of Our Financial Condition and Results of Operations.”

Derivative Gain (Loss). We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of oil. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future oil prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Interest Expense. We finance a portion of our working capital requirements and capital expenditures with borrowings under our Revolving Credit Agreement and previously our second lien credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our Revolving Credit Agreement and second lien credit facility in interest expense.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income as determined by GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated and combined financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net (loss) income before DD&A, exploration costs, impairment, acquisition costs, loss (gain) on sales of oil and natural gas properties, asset retirement obligation accretion expense, stock based compensation, net interest expense, income tax (benefit) expense, rig termination, prepayment premium on extinguishment of debt, inventory write down, (income) loss on derivative instruments, net settlements on derivative instruments, and premium realization on options that settled during the period.

Management believes Adjusted EBITDAX is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components

of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements. For further discussion and a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income, please read “Item 6. Selected Financial Data—Non-GAAP Financial Measures.”

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Recent Transactions

The historical results of operations through May 29, 2014 are based on the financial statements of our accounting predecessor, which reflects the combined results of Parsley LLC, prior to the IPO and the concurrent corporate reorganization (“Corporate Reorganization”), which increased the scope of our operations.

On February 5, 2015, we entered into an agreement to sell 14,885,797 shares of our Class A Common Stock in the Private Placement at a price of \$15.50 per share to selected institutional investors. The Private Placement closed on February 11, 2015, and resulted in gross proceeds of approximately \$230.7 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$224.0 million. The net proceeds were used to repay a portion of outstanding borrowings under our Revolving Credit Agreement and for general corporate purposes.

On September 18, 2015, we entered into an agreement to sell 14,950,000 shares of our Class A Common Stock at a price of \$15.00 per share in an underwritten public offering. The September Offering resulted in gross proceeds of approximately \$224.3 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$217.0 million. A portion of the net proceeds was used to repay borrowings outstanding under our Revolving Credit Agreement, and the remainder of the net proceeds were used to fund a portion of our capital program, including acquisitions.

On December 9, 2015, the Company and NGP entered into an agreement to sell 14,202,500 shares of Class A Common Stock, including 12,911,364 shares of Class A Common Stock issued and sold by the Company and 1,291,136 shares of Class A Common Stock sold by NGP, at a price of \$18.00 per share in an underwritten public offering (the “December Offering”). On December 10, 2015, the Underwriters exercised in full their option to purchase additional shares. The December Offering resulted in gross proceeds of approximately \$228.7 million to the Company and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately \$228.4 million. A portion of the net proceeds from the offering was used to fund the acquisition described below, and the remaining net proceeds were used to fund a portion of our capital program and for general corporate purposes. We did not receive any of the proceeds from the sale of shares by NGP.

During January 2016, we used a portion of the proceeds from the December Offering to acquire certain undeveloped acreage and producing oil and gas properties located adjacent to our existing operating areas in Upton, Reagan, and Glasscock Counties for an aggregate purchase price of \$148.5 million, of which a deposit of \$10.0 million was paid in December 2015. The acquisition added 260 gross (227 net) horizontal drilling locations across 6,040 gross (5,274 net) surface acres and production from three producing horizontal wells. The acquisition also included one drilled horizontal well that was completed by the seller prior to the transaction closing.

Incentive Unit Compensation

For the years ended December 31, 2014 and 2013, within general and administrative expenses, are amounts attributable to incentive units that, pursuant to the terms of the Parsley LLC limited liability company agreement at that date, were only entitled to a payout after a specified level of cumulative cash distributions had been received by NGP, through NGP and other preferred investors, including all of our executive officers. At December 31, 2014 and 2013, the incentive units were being accounted for as liability-classified awards pursuant to ASC Topic 718, “Compensation—Stock Compensation”, as achievement of the payout conditions required settlement of such awards by transferring cash to the incentive unit holder. There were no such costs incurred during the year ended December 31, 2015.

As part of the transactions described below under “—Corporate Reorganization,” the Parsley LLC limited liability company agreement was amended. Such amendments, among other things, converted all outstanding incentive units in Parsley LLC into PE Units. A portion of such PE Units were exchanged on a one for one basis for shares of Class A Common Stock, instead of in cash. As a result, on May 29, 2014, we accounted for the incentive unit awards as equity-classified awards pursuant to ASC Topic 718. This

resulted in the recognition of \$50.6 million of stock based compensation equal to the excess of the modified awards' fair value (based on the initial offering price of \$18.50) over the amount of cumulative compensation cost recognized prior to that date.

Stock Based Compensation

Stock based compensation includes amortization expense related to grants from our 2014 Long Term Incentive Plan. Refer to Note 9—Stock Based Compensation to our consolidated and combined financial statements included elsewhere in this Annual Report for additional discussion.

Public Company Expenses

We incur direct, incremental general and administrative expenses as a result of being a publicly traded company, including, but not limited to, increased scope of our operations as a result of recent activities and costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental general and administrative expenses are not included in our historical results of operations prior to the Corporate Reorganization.

Impairment of Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment quarterly or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and gas properties and compare the undiscounted cash flows to the carrying amount of the oil and gas properties, on a field-by-field basis, to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to estimated fair value.

As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and natural gas properties for impairment. During the period ended December 31, 2015 we recognized an impairment of our proved oil and gas properties of \$1.0 million and did not recognize an impairment during the period ended December 31, 2014. At December 31, 2015, in our significant fields that comprise 99% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by an average of 119% and individually a minimum of 6%. At December 31, 2014, in our significant fields that comprise 99% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by an average of 66% and individually a minimum of 59%.

The key assumptions used to determine the undiscounted future cash flows include, but are not limited to, future commodity prices, based on 5-year WTI futures price index for oil and NGLs and 5-year Henry Hub futures price index for natural gas, price differentials, future production estimates, estimated future capital expenditures and estimated future operating expenses. All inputs remained relatively consistent in the undiscounted future cash flow estimate from December 31, 2015 to December 31, 2014 except commodity price estimates. Future commodity pricing for oil and NGLs is based on five-year WTI futures prices, which decreased 25% from December 31, 2014 to December 31, 2015, and on five-year Henry Hub futures prices, which decreased 21% from December 31, 2014 to December 31, 2015. In terms of the reduction in value of undiscounted cash flows from December 31, 2014 to December 31, 2015, the effect of the decrease in pricing has been mitigated to a certain extent by the addition of both proved developed and proved undeveloped reserves through our continued drilling and completion of previously unproved oil and natural gas properties.

As part of our year-end reserves estimation process for future periods, we expect changes in the key assumptions used, which could be significant, including updates to future pricing estimates and differentials, future production estimates to align with our anticipated five-year drilling plan and changes in our capital costs and operating expense assumptions, which we expect to decrease further as a result of sustained lower commodity prices. There is a significant degree of uncertainty with the assumptions used to estimate future undiscounted cash flows due to, but not limited to the risk factors referred to in Item 1A. Risk Factors included elsewhere in this Annual Report.

Any decrease in pricing, negative change in price differentials, increase in capital or operating costs could negatively impact the estimated undiscounted cash flows related to our proved oil and natural gas properties. A decrease of 10% in estimated future pricing of oil and natural gas commodities as of December 31, 2015 would have resulted in an estimated additional impairment of proved oil and gas properties of \$46.9 million.

Corporate Reorganization

The historical consolidated and combined financial statements included in this Annual Report are based on the financial statements of our accounting predecessors, Parsley LLC and its predecessors, prior to the reorganization that occurred in connection with our IPO as described in Note 1—Organization and Nature of Operations – Corporate Reorganization of our consolidated and combined financial statements included elsewhere in this Annual Report. As a result, the historical consolidated and combined financial data may not give you an accurate indication of what our actual results would have been if the transactions described in Note 1—Organization and Nature of Operations – Corporate Reorganization of our consolidated and combined financial statements included elsewhere in this Annual Report had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. In addition, we have entered into the TRA with the TRA Holders in connection with our IPO. 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 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 (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 the Company 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 at our or Parsley LLC's election) 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.

Income Taxes

Our accounting predecessors are limited liability companies or limited partnerships and therefore not subject to U.S. federal income taxes. Accordingly, no provision for U.S. federal income tax has been provided for in our historical results of operations. We are taxed as a corporation under the Internal Revenue Code of 1986, as amended, and subject to U.S. federal income tax at a statutory rate of 35% of pretax earnings, and, as such, the amount of our future U.S. federal income tax will be dependent upon our future taxable income.

Our operations located in Texas are subject to an entity-level tax, the Texas margin tax, at a statutory rate of up to 1.0% of revenues less operating expenses attributable to operations in Texas.

Drilling Activity.

We began drilling operations in November 2009. As of December 31, 2015, we operated four horizontal drilling rigs and two vertical drilling rig on our properties. For the year ended December 31, 2015, our capital expenditures for drilling and completions were \$400.9 million, as compared to \$491.3 million for all of fiscal year 2014.

The amount and timing of our future capital expenditures is largely discretionary and within our control. We could choose to defer a portion of planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Results of Operations

Year ended December 31, 2015 Compared to Year ended December 31, 2014

Oil and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Year Ended December 31,		\$	%	
	2015	2014	Change	Change	
Revenues (in thousands, except percentages):					
Oil sales	\$215,795	\$232,554	\$(16,759)	(7)	%
Natural gas sales	26,582	30,642	(4,060)	(13)	%
Natural gas liquids sales	23,680	38,561	(14,881)	(39)	%
Total revenues	\$266,057	\$301,757	\$(35,700)	(12)	%
Average realized prices(1):					
Oil sales, without realized derivatives (per Bbls)	\$44.89	\$81.91	\$(37.02)	(45)	%
Oil sales, with realized derivatives (per Bbls)	56.60	81.33	(24.73)	(30)	%
Natural gas, without realized derivatives (per Mcf)	2.57	4.23	(1.66)	(39)	%
Natural gas, with realized derivatives (per Mcf)	2.72	4.32	(1.60)	(37)	%
NGLs sales (per Boe)	15.79	33.83	(18.04)	(53)	%
Average price per Boe, without realized derivatives	33.13	58.19	(25.06)	(43)	%
Average price per Boe, with realized derivatives	40.33	58.00	(17.66)	(30)	%
Production:					
Oil (MBbls)	4,807	2,839	1,968	69	%
Natural gas (MMcf)	10,339	7,245	3,094	43	%
Natural gas liquids (MBoe)	1,500	1,140	360	32	%
Total (MBoe)(2)	8,031	5,186	2,845	55	%
Average daily production volume:					
Oil (Bbls)	13,170	7,778	5,392	69	%
Natural gas (Mcf)	28,326	19,849	8,477	43	%
Natural gas liquids (Boe)	4,110	3,123	987	32	%
Total (Boe/d)	22,003	14,207	7,796	55	%

(1) 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.

(2) One Boe is equal to six Mcf of natural gas or one Bb