PARSLEY

OPERATION **THRIVE** STARTS HERE

2019 ANNUAL REPORT

OUR SPIRIT TO THRIVE

Our operational proficiency, advantaged asset base, and disciplined hedging program have enabled us to create significant value across commodity price contexts.

PARSLEY ENERGY MANAGEMENT TEAM

DEAR SHAREHOLDERS

THRIVE

Shortly after I stepped into the role of CEO in early 2019, Parsley unveiled a strategic shift in development approach to prioritize project level rate-of-return over project level net present value. In practice, this meant high-grading our well selection process, concentrating more activity in our highest return areas, and optimizing completions and spacing patterns. Overall, it meant better wells, shorter payback periods and increasing cash flow velocity. I wrote about setting this returns-focused course in last year's shareholder letter but buy-in across the organization is what gave those words weight. I want to recognize our team for embracing this mindset and helping Parsley *THRIVE* during 2019.

OPERATION THRIVE

We understood that 2019 represented a pivotal year for Parsley. Longer term goals are important but can lack a certain measure of urgency and accountability that is essential for investors in this volatile environment. Thus, we constructed a tangible scorecard for the year, which enabled investors to keep track of our progress. Externally, we referred to this as our 2019 Action Plan. Internally, we designated this as Operation Thrive and it took every single employee at Parsley to make it a reality.

One of the chief objectives of our 2019 Action Plan was to accelerate our timeline to sustainable free cash flow.[1] Thanks to the high level of execution delivered across our organization, Parsley reached this milestone ahead of schedule with free cash flow generation in both the third and fourth quarters. We took an exciting step in our corporate evolution, but our pathway to free cash flow is not meant to simply be a short-term excursion. Sustainable is the operative word. The Company cemented this corporate mindset with the initiation of a quarterly dividend program in 2019 and reinforced that commitment with a meaningful increase to our dividend in early 2020.

When we unveiled our returns-focused approach, another key corporate-level outcome we envisioned was a meaningful year-over-year improvement in capital efficiency.[2] Simply put, we were aiming to produce more barrels of oil with fewer development dollars. Our teams worked diligently on both the numerator and the denominator of this capital efficiency equation, and we ultimately recorded a 19% improvement year-over-year, which was roughly double our initial goal.

Well productivity gains validated the shift in our development approach and capital costs shifted lower due to continued operational efficiency gains, cycle time improvements, and deflationary trends on some consumables like sand and steel.

The financial and operational success we achieved during 2019 was critical, but I am equally proud of the recent strides we have made on various environmental, social and governance (ESG) initiatives. Simply put, organizational excellence on this front is quickly becoming a requisite for a license to operate.

Fostering a culture that promotes and prioritizes community stewardship is not a new revelation here at Parsley, and, over the years, we have made significant contributions to the local areas in which we operate. We have reduced our field reaction time by scaling our technology investments to provide real-time facility monitoring and enhanced virtual site visits. We have also formed an ESG-focused employee committee, led by our Chief Operating Officer, that is empowered to act on important issues that impact our employees and stakeholders. All this being said, our industry needs to do a better job telling our story on the ESG front by, among other things, becoming more transparent with respect to ESG-related data.

In December, we published our inaugural Corporate Responsibility Report – the first iteration of what will be a living document outlining the Company's ongoing commitment to environmental stewardship. Before a word of this report was ever printed, we solicited input from key stakeholders to help determine the most important topics of our report. Top shareholders, passive money managers, community officials, landowners, government agencies, NGOs, and the media all weighed in and helped shape the content. This inaugural report was steered by members of senior management and it establishes an important base line from which we can measure our progress in future years. This will be an ongoing publication that we will update annually as we continue to track and enhance the Company's commitment to environmental stewardship.

A LOOK FORWARD

2019 was a resounding success for Parsley on many fronts and we will maintain both a sense of urgency and accountability as we navigate a challenging commodity price backdrop in 2020.

In early 2020, global oil markets experienced shocks on both the supply and demand side, sending oil prices sharply lower. The combination of a strong balance sheet and corporate agility is critical in these challenging and volatile times. As an industry leader, we took immediate steps to reduce development activity while prioritizing the company's commitment to free cash flow

We Delivered on our 2019 Action Plan

GUIDING PRINCIPLES	2019 ACTION PLAN	ACCOUNTABILITY	2019 YEAR IN REVIEW
Discipline	Rate of Return ("ROR")-driven approach to well selection Accelerate timeline to self-funded growth Further increase visibility on management and shareholder alignment	Improve capital efficiency by 8–10%+ YoY [2] Outspend by less than \$250 million in any oil price environment [1] Addition of corporate returns metric to 2019 incentive plan	✓ Achieved 19%+ YoY improvement in capital efficiency [2] ✓ FY19 outspend less than \$100 million; generated free cash flow in 2H19 [1] ✓ Initiated quarterly dividend in 3Q19 [3]; delivered 13%+ CROCI [4] in 2019
Stability	Defend and extend operational efficiency gains Work with high-performing service partners on pricing and contracting Hedge to protect cash flow and balance sheet while retaining oil price upside Sustain culture that generates and prioritizes community stewardship	Increase footage drilled/completed per rig/crew over FY18 levels Improve capital efficiency by 8–10%+ YoY [2] Outspend by less than \$250 million in any oil price environment [1] Collaborate with Permian Strategic Partnership ("PSP"); publish Sustainability Report by year-end 2019	✓ 2019 footage drilled/completed per rig/crew increased 16%/14% from FY18 levels ✓ Achieved 19% YoY improvement in capital efficiency [2] ✓ Maintained high percentage of barrels hedged to support cash flow ✓ Published inaugural Corporate Responsibility Report and established Nominating, Environmental, Social & Governance Board Committee
Foresight	Leverage legacy water infrastructure investments Exercise patience on incremental crude transport agreements	Increase 3rd party water revenues and/or explore strategic alternatives Deliver healthy long-term realized oil prices while limiting minimum volume commitments	✓ Formed dedicated water team in 3Q19; increased 3rd party water volumes over 50% from 1H19 to 2H19 ✓ Dependable flow assurance, diversified pricing, and tight API gravity range (41° average) translated to favorable realized oil prices

(1) Free cash flow (outspend), a non-GAAP financial measure, means net cash provided by operating activities before transaction expenses related to the acquisition of Jagged Peak Energy Inc. and changes in operating assets and liabilities, net of acquisitions, less accrual-based development capital expenditures. For a reconciliation of the non-GAAP measure of free cash flow (outspend) to the most directly comparable GAAP measure, please see the section entitled "Free Cash Flow (Outspend) Reconciliation" at the end of this annual report. We are unable to present a reconciliation of forward-looking free cash flow because components of the calculation, including changes in working capital accounts, are inherently unpredictable. Additionally, estimating the most directly comparable GAAP measure with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort; (2) Capital efficiency calculated as barrels of organic oil production added ($Q4_1/Q4_0$, adjusted for proved developed producing ("PDP") oil base decline) per million dollars of development capital expenditures. Assumes 4Q18/4Q17 PDP oil base decline of ~45% and 4Q19/4Q18 PDP oil base decline of ~43%. Adjusted for divestitures closed after 9/30/2018; (3) Announced 8/26/2019. Paid to all equity holders including Class A stockholders and PE unitholders/Class B stockholders; (4) Addition of cash return on capital invested ("CROCI") metric into 2019 incentive plan announced in definitive proxy statement for 2019 annual meeting (filed with SEC on 4/8/2019); CROCI is calculated by dividing the sum of cash flow from operations and after-tax interest expense by the sum of average gross property, plant and equipment and average non-cash working capital. For a reconciliation of the non-GAAP financial measure of CROCI to the most directly comparable GAAP financial measure, please see the section entitled "Cash Return on Capital Invested (CROCI) Reconciliation" at the end of this annual report.

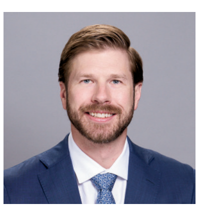
PARSLEY IS FOCUSED ON MAINTAINING VALUE FOR THE LONG TERM, AND THIS REQUIRES SHORT TERM RESPONSES WHEN POSED WITH EXTERNAL SHOCKS.

generation. We remain committed to doing whatever is necessary to protect our balance sheet in the weeks and months ahead.

Parsley is focused on maintaining value for the long term, and this requires short term responses when posed with external shocks. We will focus on our rigorous project returns process and will not destroy capital if the commodity price does not support sufficient returns. This approach worked in the 2015 – 2016 timeframe and will best position us again to emerge from this volatile time on our front foot ready to fight. In the context of a $30-$35 WTI oil price for the remainder of the year, we are targeting at least $225 million of free cash flow,[1] accomplished through activity reductions, lower service and equipment costs, and incremental downside protection built into the Company's restructured hedge positions. In a lower oil price environment, Parsley will adjust as needed to preserve its balance sheet.

In this challenging macro environment, Parsley is committed to continuous organizational improvement as we look to preserve shareholder value and weather this storm. We are striving to preserve and build upon the hard-earned capital efficiency gains we achieved in 2019. If you are not climbing the ladder, you are getting passed by. We also remain committed to a successful integration of our Jagged Peak acquisition, which includes achieving stated objectives on synergy capture and flaring mitigation.

Our team has a proven ability to achieve ambitious goals. With a clear vision and a solid foundation of success to build upon, I look forward to tracking our progress in 2020.



Matt Gallagher
President and Chief Executive Officer

JAGGED PEAK ACQUISITION

In October 2019, Parsley announced it had entered into a definitive agreement to acquire Jagged Peak Energy Inc. in an all-stock transaction, a deal that was catalyzed in part due to the goals we set forth in Operation Thrive.

The acquisition of Jagged Peak by Parsley was truly a natural fit. Parsley possessed an institutional familiarity with Jagged Peak's Delaware Basin assets, its acreage footprint and water infrastructure dovetailed into our legacy Delaware Basin position, and its corporate culture aligned with our core values. Jagged Peak's high-margin, oil-weighted asset base further enhanced our long-term free cash flow potential and integrated smoothly into our near-term development program.

Jagged Peak Acquisition Highlights

- *Complementary, High-Margin Delaware Basin Footprint*
- *Accretive on Key Metrics*
- *Corporate Cost Optimization Accrues to Shareholders*
- *Capital Efficiency Gains*
- *Creates Expansive Company-Owned Water Infrastructure Network*
- *Accelerates Capital Cost Advantages*
- *Maintains Strong Balance Sheet*

MANAGEMENT

EXECUTIVE OFFICERS

MATT GALLAGHER
President and Chief Executive Officer

BRYAN SHEFFIELD
Executive Chairman

DAVID DELL'OSSO
Executive Vice President –
Chief Operating Officer

RYAN DALTON
Executive Vice President –
Chief Financial Officer

COLIN ROBERTS
Executive Vice President –
General Counsel

SENIOR VICE PRESIDENTS

CECILIA CAMARILLO
Senior Vice President –
Accounting

MIKE HINSON
Senior Vice President –
Corporate Affairs, Co-founder

STEPHANIE REED
Senior Vice President –
Corporate Development,
Land, and Midstream

PAUL TREADWELL
Senior Vice President –
Production Operations, Co-founder

VICE PRESIDENTS

MARK BROWN
Vice President –
Security and Risk Management

CARRIE ENDORF
Vice President –
Reservoir Engineering and Planning

ROB HEMBREE
Vice President –
Information Technology

JODY JORDAN
Vice President –
Marketing

LANDON MARTIN
Vice President –
Drilling and Completions

KRISTIN McCLURE
Vice President –
Human Resources

TODD PETERS
Vice President –
Geoscience

KYLE RHODES
Vice President –
Investor Relations

MARK TIMMONS
Vice President –
Field Operations

BOARD OF DIRECTORS

BRYAN SHEFFIELD
Chairman

MATT GALLAGHER
Director

A.R. ALAMEDDINE (2)(3)(4)(5)
Director

RONALD BROKMEYER (2)(4)
Director

WILLIAM L. BROWNING (1)(2)
Director

DR. HEMANG DESAI (1)(2)
Director

KAREN HUGHES (2)(3)
Director

JAMES J. KLECKNER (4)
Director

DAVID SMITH (1)(3)
Director

S. WIL VANLOH, JR. (3)
Director

JERRY WINDLINGER (1)(4)
Director

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Nominating, Environmental, Social and Governance Committee
(4) Member of the Reserves Committee
(5) Lead Director

CONTACT INFORMATION

AUSTIN OFFICE
303 Colorado Street, Suite 3000
Austin, TX 78701
737-704-2300

MIDLAND OFFICE
1703 E. County Road 120
Midland, TX 79706
432-818-2100

COMMON STOCK

The company's Class A common stock is traded on the New York Stock Exchange under the symbol PE.

INDEPENDENT AUDITOR

KPMG LLP
2323 Ross Avenue • Suite 1400
Dallas, TX 75201

TRANSFER AGENT

For shareholder questions regarding transfer of shares, lost stock certificates, duplicate mailings, change of address or other similar matters, please contact our Transfer Agent:

American Stock Transfer & Trust Company
6201 15th Avenue, Brooklyn, NY 11219
800-937-5449
info@astfinancial.com

INDEPENDENT PETROLEUM ENGINEERS

Netherland, Sewell & Associates, Inc.
2100 Ross Avenue • Suite 2200
Dallas, TX 75201

VISIT OUR WEBSITE

www.parsleyenergy.com

INVESTOR RELATIONS

Shareholders, brokers, securities analysts, and portfolio managers seeking information about the company may email us at ir@parsleyenergy.com or call:
Kyle Rhodes
Vice President – Investor Relations
512-505-5199

ANNUAL MEETING

The Annual Meeting of Stockholders will be held via live webcast at: www.virtualshareholdermeeting.com/PE2020 on Friday, May 21, 2020, at 8:00 a.m. Central Time.

2019 ANNUAL REPORT

FORM 10-K

PARSLEY

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, 2019

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 **(State or other jurisdiction of incorporation or organization)**	**46-4314192** **(I.R.S. Employer Identification No.)**
303 Colorado Street, Suite 3000 **Austin, Texas** **(Address of principal executive offices)**	**78701** **(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	Trading Symbol	Name of each exchange on which registered
Class A common stock, $0.01 par value	PE	**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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2019 was approximately $5,290,889,558 based on the closing price as reported on the New York Stock Exchange.

As of February 21, 2020, the registrant had 377,559,296 shares of Class A common stock and 35,147,222 shares of Class B common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2020 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, 2019

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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 and acquisitions, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "intend," "potential," "could," "may," "foresee," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if made earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to unduly rely on them. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed under "Item 1A. Risk Factors," as well as those factors summarized below.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- leasehold, minerals or business acquisitions or divestitures, including our recently completed Jagged Peak Acquisition (as defined herein);
- ability to achieve the anticipated synergies, operational efficiencies and returns from the Jagged Peak Acquisition;
- 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;
- costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

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

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

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

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

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

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

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

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

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

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

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

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

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

(8) *Deterministic.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(9) *Developed acreage.* Acreage spaced or assigned to productive wells, excluding undrilled acreage held by production under the terms of the applicable lease.

(10) *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.

(11) *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.

(12) *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).

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

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are referred to as geological and geophysical costs or G&G costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(14) *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.

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

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

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

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

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

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

(21) *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.

(22) *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.

(23) *LIBOR.* London Interbank Offered Rate.

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

(25) *MBoe.* One thousand barrels of oil equivalent.

(26) *Mcf.* One thousand cubic feet of natural gas.

(27) *MMBoe.* One million barrels of oil equivalent.

(28) *MMBtu.* One million British thermal units.

(29) *MMcf.* One million cubic feet of natural gas.

(30) *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.

(31) *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.

(32) *NYMEX.* The New York Mercantile Exchange.

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

(34) *Parsley LLC Agreement*. The Limited Liability Company Agreement of Parsley LLC, dated June 11, 2013, thereafter amended and restated by the Second Amended and Restated Limited Liability Company Agreement, dated May 29, 2014, thereafter amended and restated by the Third Amended and Restated Limited Liability Company Agreement, dated February 20, 2019, thereafter amended and restated by the Fourth Amended and Restated Limited Liability Company Agreement, dated July 22, 2019, as in effect as of the applicable date.

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

(36) *Probabilistic*. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(37) *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.

(38) *Proved reserves*. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence, within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

(39) *Proved undeveloped reserves or PUDs*. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The following rules apply to PUDs:

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances;

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time; and

(iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

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

(42) *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.

(43) *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.

(44) *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.

(45) *SEC.* The United States Securities and Exchange Commission.

(46) *Spacing*. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, *e.g.*, 40-acre spacing, and is often established by regulatory agencies.

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

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

(49) *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.

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

(51) *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.

EXPLANATORY NOTE

On January 10, 2020, through a series of transactions, we acquired Jagged Peak Energy Inc., a Delaware corporation that previously traded on the New York Stock Exchange ("NYSE") under the symbol "JAG" ("Jagged Peak"), pursuant to the Agreement and Plan of Merger, dated as of October 14, 2019, among Parsley Energy, Inc., Jackal Merger Sub, Inc., a Delaware corporation and wholly owned subsidiary of Parsley Energy, Inc., and Jagged Peak (the "Jagged Peak Acquisition"). Although this Annual Report is being filed following the completion of the Jagged Peak Acquisition, unless otherwise specifically noted herein, information set forth herein only relates to the period as at and for the fiscal year ended December 31, 2019 and therefore does not include information relating to Jagged Peak or its subsidiaries as of and for such periods. Accordingly, unless otherwise specifically noted herein, references herein to "Parsley," "we," "us," "our" or the "Company" refer only to Parsley Energy, Inc. and its subsidiaries prior to the Jagged Peak Acquisition and do not include Jagged Peak or its subsidiaries.

PART I

ITEM 1. BUSINESS

Overview

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

As of December 31, 2019, we had an interest in 753 gross (578 net) productive horizontal wells, of which 616 gross (470.5 net) wells are in the Midland Basin and 137 gross (107.5 net) wells are in the Delaware Basin. As of December 31, 2019, we operated 597 gross (558.9 net) of these horizontal wells and had the rights to develop 246,405 gross (191,179 net) acres in the Permian Basin, with approximately 202,773 gross (149,615 net) acres located in the Midland Basin and 43,632 gross (41,564 net) acres located in the Delaware Basin. We intend to grow our reserves and production through the drilling and development of our multi-year inventory of identified drilling locations.

At December 31, 2019, our estimated proved oil, natural gas and NGLs reserves were 592.3 MMBoe based on an internal reserve report prepared by our internal staff of petroleum engineers and audited by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent third-party petroleum consulting firm. Of these reserves, approximately 64% are classified as proved developed producing. Based on this report, at December 31, 2019, our proved developed reserves were approximately 54% oil, 21% natural gas and 25% NGLs. These calculated percentages include proved developed non-producing reserves.

Our 2020 budget for capital development expenditures is approximately 1,600.0 million to $1,800.0 million. We expect approximately 25% to 30% of this budget to be associated with drilling and completions for proved undeveloped reserves as of December 31, 2019. Our capital budget excludes any amounts that may be paid for acquisitions. The amount and timing of our 2020 capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned 2020 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Recent Events

*Jagged Peak Acquisitio*n

As part of the Jagged Peak Acquisition, each eligible share of Jagged Peak common stock was automatically converted into the right to receive 0.447 shares of our Class A common stock, par value $0.01 per share (“Class A common stock”). As a result, we issued or distributed approximately 95.9 million shares of Class A common stock to former Jagged Peak stockholders upon the consummation of the Jagged Peak Acquisition, including approximately 1.0 million treasury shares reissued by the Company.

In connection with the completion of the Jagged Peak Acquisition, our subsidiary, Parsley Energy, LLC (“Parsley LLC”), assumed Jagged Peak’s guarantee of $500.0 million in aggregate principal amount of the 5.875% senior notes due 2026 (the “Jagged Peak 2026 Notes”) of its subsidiary, Jagged Peak Energy LLC, a Delaware limited liability company (“Jagged Peak LLC”), and repaid in full all outstanding obligations under Jagged Peak’s credit facility by drawing on our revolving credit agreement (“Revolving Credit Agreement”). The Jagged Peak 2026 Notes are the senior unsecured obligations of Jagged Peak LLC, which became a wholly owned subsidiary of Parsley LLC upon the completion of the Jagged Peak Acquisition, and the other subsidiaries of Parsley LLC that are guarantors of the Jagged Peak 2026 Notes.

4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes

On February 11, 2020, Parsley LLC and Parsley Finance Corp. (“Finance Corp.” and together with Parsley LLC, the “Issuers”) issued $400.0 million aggregate principal amount of 4.125% senior unsecured notes due 2028 (the “2028 Notes”) in an offering that was exempt from registration under the Securities Act (the “2028 Notes Offering”). The 2028 Notes Offering resulted in net proceeds to us, after deducting estimated fees and expenses, of approximately $395.2 million. We intend to use such net proceeds and borrowings under the Revolving Credit Agreement to redeem all of our 6.250% senior unsecured notes due 2024 (the "2024 Notes") at a redemption price of 104.688%, plus accrued and unpaid interest to the redemption date, pursuant to the terms of the indenture relating to the 2024 Notes (the "2024 Notes Redemption"). We expect that the redemption date for the 2024 Notes Redemption will be March 7, 2020.

Our Strategy

We aim to increase long-term stockholder value by producing affordable and reliable energy in an efficient, safe and sustainable manner. Our business strategy is centered around the following strategic objectives:

- Increase and stabilize free cash flow generation through capital efficient development activity.
- Enhance returns through continued improvement in operational and cost efficiencies.
- Develop our assets in an efficient, safe and environmentally responsible manner.
- Maintain financial flexibility with a strong balance sheet.

Our Strengths

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

- Economies of scale applied to an extensive set of reinvestment opportunities.
- Established resource base and acreage position in the core of the Permian Basin.
- Advantaged operating margins.
- Incentivized management team with significant equity stake.
- Operating control over substantially all our horizontal production.

Organizational Structure

We are a holding company that was incorporated as a Delaware corporation on December 11, 2013 for the purpose of facilitating our initial public offering (our "IPO") and to become the sole managing member of Parsley LLC. Our sole material asset as of December 31, 2019 consisted of 281,241,443 PE Units and, as the sole managing member, we hold a controlling equity interest in Parsley LLC and manage the business and affairs of Parsley LLC and its subsidiaries. We consolidate the financial and operating results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interests in Parsley LLC held by the holders of PE Units (each, a "PE Unitholder") other than Parsley Energy, Inc.

Pursuant to the Parsley LLC Agreement, PE Unitholders (other than Parsley Energy, Inc.) generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of Class B common stock, par value $0.01 per share ("Class B common stock")) for shares of Class A common stock at an exchange ratio of one share of Class A common stock for each PE Unit (and corresponding share of Class B common stock) exchanged (subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications), or, if either we or Parsley LLC so elects, cash (the "Cash Option"). In addition, in connection with our IPO, we entered into a Tax Receivable Agreement, dated May 29, 2014 (the "TRA"), among Parsley LLC and certain PE Unitholders (each such person and any permitted transferee, a "TRA Holder"). This agreement generally provides for the payment by us to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state or local income tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of (i) any tax basis increases resulting from the contribution in connection with our IPO by such TRA Holder of all or a portion of its PE Units to us in exchange for shares of Class A common stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A common stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. We will retain the benefit of the remaining 15% of these cash savings.

Oil and Natural Gas Production and Operations

Production and Price History

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

	Year Ended December 31, 2019	2018	2017
Production revenues (in thousands)[1]:			
Oil sales	$ 1,757,315	$ 1,536,244	$ 802,230
Natural gas sales	36,774	51,231	56,571
Natural gas liquids sales	155,888	227,272	103,193
Total production revenues	$ 1,949,977	$ 1,814,747	$ 961,994
Average realized prices[2]:			
Oil (per Bbl)	$ 55.50	$ 60.59	$ 48.95
Natural gas (per Mcf)	0.71	1.37	2.43
Natural gas liquids (per Bbl)	14.17	27.21	22.87
Average price per Boe	37.99	45.44	38.80
Production[1]:			
Oil (MBbls)	31,664	25,356	16,390
Natural gas (MMcf)	51,933	37,365	23,326
Natural gas liquids (MBbls)	11,002	8,353	4,512
Total (MBoe)	51,322	39,937	24,792
Average daily production volume[1]:			
Oil (Bbls)	86,751	69,468	44,904
Natural gas (Mcf)	142,282	102,370	63,907
Natural gas liquids (Bbls)	30,142	22,885	12,362
Total (Boe)	140,608	109,416	67,923

(1) Natural gas and NGLs sales and associated production volumes for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC Topic 606, *Revenue from Contracts with Customers* ("ASC 606"), effective January 1, 2018.

(2) Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Production Revenues" for average realized prices after the effects of our realized commodity hedging transactions.

Approximately 85%, 83% and 88% of our total estimated proved reserves as of December 31, 2019, 2018 and 2017, respectively, were attributable to the Midland Basin, and approximately 15%, 17% and 12% of our total estimated proved reserves as of December 31, 2019, 2018 and 2017, respectively, were attributable to the Delaware Basin. The following table sets forth information regarding our net production of oil, natural gas and NGLs by basin for the periods indicated:

	Year Ended December 31,								
	2019			2018			2017		
	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total
Production[1]:									
Oil (MBbls)	24,656	7,008	31,664	18,881	6,475	25,356	14,082	2,308	16,390
Natural gas (MMcf)	45,515	6,418	51,933	31,873	5,492	37,365	20,835	2,491	23,326
Natural gas liquids (MBbls)	9,698	1,304	11,002	7,243	1,110	8,353	4,087	425	4,512
Total (MBoe)	41,940	9,382	51,322	31,436	8,501	39,937	21,641	3,151	24,792

(1) Natural gas and NGLs sales and associated production volumes for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

Productive Wells

As of December 31, 2019, we had an interest in 753 gross (578 net) productive horizontal wells and 1,199 gross (765.3 net) productive vertical wells. Productive wells consist of producing wells and wells mechanically capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of our fractional working interests owned in gross wells. As of December 31, 2019, we owned an immaterial number of productive wells related to the production of natural gas.

Well Operations

As of December 31, 2019, we operated 597 gross (558.9 net) horizontal wells and 872 gross (723.1 net) vertical wells. As the operator, we design and manage the development of our wells and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the production from the properties we operate, both for our account and for the accounts of third-party working, royalty and overriding royalty interest owners in these properties. We sell our production at market prices to a relatively small number of purchasers, as is customary in the oil and gas exploration, development and production business. For the years ended December 31, 2019, 2018 and 2017, the following customers accounted for more than 10% of our revenue:

	Year Ended December 31,		
	2019	2018	2017
Shell Trading (US) Company	55%	53%	62%
Lion Oil, Inc.	30%	22%	3%
Targa Pipeline Mid-Continent, LLC	8%	11%	13%

If a significant customer were to stop purchasing oil and natural gas from us, our revenue could decline and our operating results and financial condition could be harmed. While we believe that we could procure substitute or additional customers to offset the loss of one or more of our current significant customers, there is no assurance that we would be successful in doing so on terms acceptable to us or at all. Please see *Note 2—Summary of Significant Accounting Policies—Significant Customers* to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Transportation and Delivery Commitments

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by third-party in-basin 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 third-party in-basin gathering systems. In addition, we transport the majority of our produced water by pipeline connected to our operated salt water disposal wells rather than by truck. However, due to the inaccessibility of certain of our wells, some produced water is transported by truck.

We sell oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. As of December 31, 2019, we were party to the following contracts related to the transportation and/or sale of fixed and determinable quantities of crude oil:

- A contract providing transportation from one of our third-party gathering pipeline systems through which we transport or sell crude oil. Under this contract, we have committed to deliver minimum average volumes of 45,000 Bbls/day from November 1, 2019 to June 30, 2020, 50,000 Bbls/day from July 1, 2020 to September 30, 2022, 75,000 Bbls/day from October 1, 2022 to June 30, 2025, and 25,000 Bbls/day from July 1, 2025 to September 30, 2027. By mutual agreement of the parties, at any time during the term of the contract, we may deliver up to 15,000 Bbls/day through another third-party crude oil gatherer with whom we have a contract and any such delivered barrels will reduce the minimum volume requirements under this contract and, in turn, count against the minimum volume requirements contained in the contract that we have entered into with such other crude oil gatherer.
- A contract for the transportation and/or sale of crude oil, pursuant to which we have committed to deliver approximately 11.4 MMBbl during the period from February 1, 2020 to February 28, 2022. The term of this contract may be extended at our option by up to two years.
- A contract for the sale of crude oil that is subject to the commencement of operations of a third-party terminal and pipeline system. Upon the earlier of (i) the commencement of operations and (ii) January 1, 2022, we will be required to deliver a minimum average volume of 25,000 Bbls/day for seven years and year-to-year thereafter for so long as the contract is not terminated by the parties.
- A contract for the transportation and/or sale of crude oil that is subject to the commencement of operations of a third-party terminal and pipeline system. Upon the commencement of operations, we will be required to deliver a minimum average volume of 5,000 Bbls/day during the first month, which will increase by 5,000 Bbls/day each month until we are required to deliver a minimum average volume of 35,000 Bbls/day during the seventh month. We will then be required to deliver 35,000 Bbls/day until three years following the commencement of operations of the third-party terminal and pipeline system. At the completion of the initial three-year period, our counterparty will have the option to extend the contract for up to four additional years, but if such option is not exercised, we will be have the option to extend the contract for up to two additional years.

In addition, on January 10, 2020, in connection with completion of the Jagged Peak Acquisition, we assumed certain contracts providing for transportation and sale of crude oil in the Delaware Basin. Under these contracts, we are committed to deliver a minimum average volume of 30,000 Bbls/day through September 30, 2024.

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

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons and raising additional capital, which could have a material adverse effect on our business.

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

Seasonality of Business

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

Oil and Natural Gas Leases

The oil and natural gas lease agreements covering our properties typically provide for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%. Where we own minerals underlying properties that we operate, our net revenue interest will be higher.

Markets for Sale of Production

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

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

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

Regulation of the Oil and Natural Gas Industry

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

Regulation Affecting Production

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

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

Regulation Affecting Sales and Transportation of Commodities

Sales prices for oil, natural gas and NGLs are not currently regulated and therefore are dictated by the prevailing market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and natural gas, or the prices charged for these commodities, might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

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

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

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

In addition to the regulation of natural gas pipeline transportation, the FERC has jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to the FERC's jurisdiction pursuant to the Energy Policy Act of 2005. Under this law, it is unlawful for "any entity," including a producer such as us, that is otherwise not subject to the FERC's jurisdiction under the Natural Gas Act of 1938 to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas, or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud, to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading, or to engage in any act or practice that operates as a fraud or deceit upon any person. The Energy Policy Act of 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 up to $1,291,894 per day per violation (adjusted annually based on inflation) and disgorge profits associated with any violation. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

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

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

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

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

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

In addition to the FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission (the "FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1,231,690 per violation per day (adjusted annually based on inflation). In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (the "CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement its new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1,212,866 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

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

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

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

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

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. A change in the classification of exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

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

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the "USACE") or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule redefining the scope of the EPA's and the USACE's jurisdiction under the CWA with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands (the "WOTUS" rule). Following the change in U.S. presidential administrations in 2016, there have been several attempts to modify or eliminate this rule. Most recently, in September 2019, the EPA and USACE rescinded the WOTUS rule. Legal challenges have occurred for both the 2015 rule and the 2019 rescission. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent the original WOTUS rule or any replacement rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

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

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations.

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

Air Emissions

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

Regulation of Greenhouse Gas Emissions

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of greenhouse gases ("GHGs") as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the Clean Air Act, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the Department of Transportation (the "DOT"), implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is an agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquidified natural gas ("LNG") export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

Hydraulic Fracturing Activities

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

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

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

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

Endangered Species Act and Migratory Birds

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

OSHA

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

Related Permits and Authorizations

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

Related Insurance

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

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2019, nor do we anticipate that such expenditures will be material in 2020.

Employees

As of December 31, 2019, we employed 496 people. We consider our relations with employees to be satisfactory. Our future success will depend in part on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We regularly utilize the services of independent contractors to perform various field and other services.

Available Information

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

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

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

ITEM 1A. RISK FACTORS

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

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

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

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

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

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. As of December 31, 2019, NYMEX WTI oil futures contract prices and NYMEX Henry Hub gas futures prices were $61.06 per barrel and $2.19 per MMBtu, respectively. During 2019, the low price for each of NYMEX WTI oil futures and NYMEX Henry Hub gas futures was $45.41 per barrel and $2.07 per MMBtu, respectively.

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

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

We have acquired significant amounts of unproved property, including certain of the property acquired in connection with the Jagged Peak Acquisition, in order to further our development efforts and expect to continue to undertake similar acquisitions in the future. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and improve our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive, that we will recover all or any portion of our investment in such unproved property or wells, or that production from wells drilled by us will achieve our desired cash flow and rate of return for all or any portion of our properties.

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

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

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with each of these assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline and we cannot necessarily observe structural and environmental problems during our inspection. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.

Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the development of our oil and natural gas reserves, which we finance with cash on hand, cash flow from operations, borrowings under our Revolving Credit Agreement and proceeds received from any divestiture of our oil and gas properties. Our 2020 budget for capital development expenditures is approximately $1,600.0 million to $1,800.0 million, which excludes any amounts that may be paid for acquisitions. The amount and timing of our 2020 capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned 2020 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Our cash on hand, cash flow from operations and access to capital are subject to a number of variables beyond our control, including:

- the volume of oil, natural gas and NGLs we are able to produce from existing wells;
- the ratio of oil to natural gas and NGLs we are able to produce from existing wells;
- the prices at which our production is sold;
- our proved reserves;
- our ability to acquire, locate and produce new reserves;
- our ability to borrow under our Revolving Credit Agreement;
- the global credit and securities markets; and
- the ability and willingness of lenders and investors to provide capital and the cost of such capital.

If our revenues, liquidity or the borrowing base under our Revolving Credit Agreement decrease as a result of lower oil, natural gas and NGLs prices, operating difficulties, declines in reserves or for any other reason, and we require additional capital, we may have limited ability to obtain the capital necessary to sustain our operations and production growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in the curtailment of our development operations, which could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations. For additional information regarding our 2020 budget for capital development expenditures and sources of liquidity, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity."

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

Accounting rules require that we periodically review the carrying values of our proved and unproved properties for possible impairment. Based on commodity prices and other specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying values of our properties. A write-down would constitute a non-cash charge to earnings. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Oil and Natural Gas Properties" and *Note 16—Disclosures About Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our recent impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

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

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

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

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

- delays imposed by or resulting from compliance with regulatory requirements, including limitations on wastewater disposal, discharge of GHGs, hydraulic fracturing and other potential environmental impacts from our operations, including protections for threatened or endangered plant and animal life;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in the construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse or severe weather conditions or events, including any such conditions or events that may be related to climate change;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, the presence of naturally occurring radioactive materials and the unauthorized discharge of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGLs prices;

- limited availability of financing at acceptable terms;
- loss of title or other title-related issues and disputes; and
- limitations in the market for oil, natural gas and NGLs.

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

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

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

As of December 31, 2019, we had approximately $2.2 billion of outstanding indebtedness, reflecting the principal amount of our senior unsecured notes. Pro forma for the Jagged Peak Acquisition, the 2028 Notes Offering and the 2024 Notes Redemption, as of December 31, 2019, we had approximately $3.1 billion of outstanding indebtedness, consisting of $365.7 million principal amount outstanding under the Revolving Credit Agreement and $2.7 billion principal amount of our senior unsecured notes (including the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition, but excluding the 2024 Notes, which we expect to redeem on March 7, 2020).

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Revolving Credit Agreement and our senior unsecured notes (including the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition), will depend on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control and can vary significantly from year to year. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay planned investments and capital expenditures, or to sell assets, seek additional financing in the debt or equity markets or restructure or refinance our indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict us from pursuing some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a decline in our credit ratings, which could harm our ability to incur additional indebtedness.

In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and may be required to divest of material assets or operations to meet our debt service and other obligations. Our Revolving Credit Agreement and the indentures governing our senior unsecured notes (including the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition) restrict our ability to divest of assets and our use of the proceeds from such divestitures. We may not be able to consummate those divestitures or, if consummated, the proceeds from such divestitures may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not allow us to meet our debt service obligations.

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

Our Revolving Credit Agreement and the indentures governing our senior unsecured notes (including the indenture governing the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition) contain a number of significant restrictive covenants, including covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase, or retire our capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or payments from our restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- form unrestricted subsidiaries.

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

Our Revolving Credit Agreement also limits the amount we can borrow up to the lowest of (i) the borrowing base (which currently stands at $2.7 billion), (ii) the aggregate elected borrowing base commitments (which currently stand at $1.0 billion) and (iii) $5.0 billion. The borrowing basis is subject to scheduled annual and other elective borrowing base redeterminations based upon the projected revenues from the oil and natural gas properties securing our loan. As a result of any redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Agreement. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid.

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

If we are unable to comply with the various restrictions and covenants in the agreements governing our indebtedness, including our Revolving Credit Agreement and the indentures governing our senior unsecured notes (including the indenture governing the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition), there could be an event of default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting certain financial ratios and tests, may be affected by events beyond our control (for example, the deterioration of market or other economic conditions). We cannot assure you that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests.

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

If any of these events occur, our assets may 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 may not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend the agreements governing our indebtedness or obtain needed waivers on satisfactory terms.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of the commodities we sell, we enter into commodity derivative contracts for a significant portion of our production, with an emphasis on oil production, including put spread options, three-way collars and swap contracts. In connection with the Jagged Peak Acquisition, we also assumed Jagged Peak's outstanding hedge positions at closing, and we bear the economic impact of such hedges. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs." While intended to reduce the effects of crude oil and natural gas price volatility, such transactions may limit our potential gains if prices rise over the price established by such arrangements. Conversely, our hedging program may be inadequate to protect us from continuing and prolonged declines in oil or natural gas prices.

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

Our derivative transactions expose us to counterparty credit risk.

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

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

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

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

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

- the quantities of oil and gas that we ultimately recover;

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

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

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

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

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Therefore, the estimates of Standardized Measure in this Annual Report should not be construed as accurate estimates of the current market value of our proved reserves.

Approximately 15% of our net leasehold acreage is undeveloped and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our future oil and natural gas reserves and production.

As of December 31, 2019, approximately 15% of our net leasehold acreage was undeveloped or acreage on which wells have not been completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established within a defined period of time on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage. Further, to the extent we determine that it is not economic to develop particular undeveloped acreage, we may intentionally allow leases to expire. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. Failing to develop our undeveloped leasehold acreage or allowing leases to expire could result in leasehold abandonment, impairment or a reduction in our oil and natural gas reserves and production, any of which could have a material adverse effect on our financial results. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Oil and Natural Gas Properties" and *Note 16—Disclosures About Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our leasehold abandonments and impairments. For the year ended December 31, 2019, as a result of periodic assessments of our unproved properties that are not held-by-production, we recorded non-cash leasehold abandonment and impairment charges of $62.8 million relating to acreage expiring in future periods because we have no current plans to drill or extend the leases prior to their expiration. For the years ended December 31, 2019, 2018 and 2017, we recognized non-cash leasehold abandonment and impairment expense of $36.4 million, $33.8 million and $32.9 million, respectively, due to leases expiring during those periods.

Our producing properties are located in the Permian Basin of west Texas, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Permian Basin of west Texas. At December 31, 2019, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions.

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

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

The volume of oil and natural gas that we can produce is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, processing, fractionation, refining or export facilities we utilize, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months and, in many cases, we may be provided only limited, if any, advance notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or any inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

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

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

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

Due to the nature of our drilling programs and the oil and natural gas industry in general, we are party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, throughput volume commitments and drilling commitments. In the event of decreased development activities or production-related difficulties, we could be required to pay for unutilized goods or services or we may be unable to meet these contractual obligations. For additional information, see *Note 14—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report.

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

It is generally our practice in acquiring oil and natural gas leases or mineral interests not to incur the expense of retaining lawyers to examine the title to the leases and underlying mineral interests at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office. The existence of a material title deficiency can reduce the value of a lease or mineral interest or render it worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property. In addition, to the extent title opinions or other investigations prior to the commencement of drilling operations reflect title defects affecting such properties, we are typically responsible for curing any such defects at our expense. The discovery of any such title defects could also delay or prohibit the commencement of drilling operations on the affected properties.

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

At December 31, 2019, 36% of our total estimated proved reserves were classified as proved undeveloped. Our 210,590 MBoe of estimated proved undeveloped reserves will require an estimated $2.2 billion of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources, such as cash flow from operations, capital markets and our Revolving Credit Agreement. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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

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

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing acquisition and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to acquire and develop or find sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease and our business, financial condition and results of operations would be adversely affected. Further, the horizontal decline curve we use to project our future production is subject to numerous assumptions and limitations.

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

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including, but not limited to, the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and natural gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See "Item 1. Business—Oil and Natural Gas Production and Operations." We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production. The loss of one or more of these significant purchasers, and our inability to sell our production to other customers on terms we consider acceptable, could materially and adversely affect our business, financial condition, results of operations and cash flow.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

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

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

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

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

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

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

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

- unexpected drilling conditions;
- loss of title or other titled related issues;
- abnormal pressure or irregularities in geological formations;
- equipment failure or accidents;
- adverse or severe weather conditions or events;
- reductions or volatility in oil, natural gas and NGLs prices;

- political events, public protests, civil disturbances, terrorist acts or cyber-attacks;
- surface access restrictions;
- failure to obtain regulatory and third-party permits and approvals;
- compliance with environmental and other governmental or contractual requirements;
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services;
- oil, natural gas or NGLs gathering, transportation, processing, fractionation, refining and export availability restrictions or limitations; and
- limited availability of financing at acceptable terms.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause declines or volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

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

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

- recoverable reserves;
- future oil, natural gas and NGLs prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

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

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. 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. In addition, our Revolving Credit Agreement and the indentures governing our senior unsecured notes (including the Jagged Peak 2026 Notes, which we assumed in connection with the Jagged Peak Acquisition), impose certain limitations on our ability to enter into mergers or combination transactions. These agreements also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may not realize anticipated benefits from acquisitions.

We have completed a number of acquisitions to strengthen our position and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

With respect to the Jagged Peak Acquisition, there can be no assurance that we will be able to successfully integrate Jagged Peak's assets or otherwise realize the expected benefits of the transaction. Difficulties in integrating Jagged Peak into Parsley may result in the combined company performing differently than expected, or in operational challenges or failures to realize anticipated efficiencies. Potential difficulties that may be encountered in the integration process include, among other factors: difficulties integrating the businesses of Jagged Peak and Parsley in a manner that permits us to achieve the full revenue and cost savings anticipated from the transaction; complexities associated with managing a larger and more complex business; difficulties realizing anticipated operating synergies; difficulties integrating personnel, vendors and business partners; loss of key employees; potential unknown liabilities and unforeseen expenses, delays or regulatory conditions; performance shortfalls at one or both of the companies as a result of the diversion of management's attention to integration efforts; inconsistencies between each company's standards, controls, policies and procedures; and the disruption of, or the loss of momentum in, each company's ongoing business.

We have also incurred, and expect to continue to incur, a number of costs associated with completing the Jagged Peak Acquisition and combining the businesses of Jagged Peak and Parsley. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the two companies, may not initially offset integration-related costs or achieve a net benefit in the near term, or at all.

Our future success will depend, in part, on our ability to manage our expanded business by, among other things, integrating the assets, operations and personnel of Jagged Peak and Parsley in an efficient and timely manner; consolidating systems and management controls; and successfully integrating relationships with customers, vendors and business partners. Failure to successfully manage the combined company may have an adverse effect on our business, reputation, financial condition and results of operations.

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

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

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

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

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

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years, and many environmental statutes contain citizen suit provisions that allow private parties to sue to enforce environmental laws and regulations. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. See “Item 1. Business—Regulation of the Oil and Natural Gas Industry” for a further description of the laws and regulations that affect us.

If we experience liquidity concerns, we could face a downgrade in our credit ratings, which could negatively impact our cost of and ability to access capital.

As of December 31, 2019, our long-term senior unsecured debt was rated Ba3 with a stable outlook by Moody’s Investors Service, Inc. and BB- with a positive outlook by Standard & Poor’s Ratings Services. On January 13, 2020, our long-term senior unsecured debt was upgraded to BB with a stable outlook by Standard & Poor’s Ratings Services. Although we do not anticipate any near-term downward revisions to our credit ratings, we cannot be assured that our credit ratings will not be downgraded in the future.

A downgrade in our credit ratings could negatively impact (i) our costs of capital or our ability to effectively execute aspects of our strategy, (ii) our ability to raise debt in the public debt markets (in which case, the cost of any new debt could be higher than our outstanding debt) and (iii) our ability to obtain additional financing with acceptable interest rates, fees and other terms. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

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

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

Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 to impose penalties for current violations of up to $1,291,894 per day for each violation (adjusted annually based on inflation) and disgorgement of profits associated with any violation. While our operations have not been regulated by the FERC as a natural gas company under this law, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1 million per day and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to crude oil swaps and futures contracts as that granted to the CFTC with respect to crude oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,212,866 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in “Item 1. Business—Regulation of the Oil and Natural Gas Industry.”

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for our products.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the Clean Air Act, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is an agreement, the United Nations-sponsored “Paris Agreement,” for nations to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States’ withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

Finally, many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect our results of operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing or fluid disposal activities could result in increased costs and additional operating restrictions or delays and could materially and adversely affect our production.

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

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

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells. For example, severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdictions for drilling and hydraulic fracturing in order to protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may incur increased costs to obtain water from non-local sources or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

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

We believe that we follow applicable standard industry practices and legal requirements for hydraulic fracturing and fluid disposal. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells. Increased regulation and attention given to water disposal and induced seismicity could also lead to greater opposition, including litigation, to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. Please read "Item 1. Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

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

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. For example, recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

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

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

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that we or they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations by us or other operators could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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

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

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

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

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

We are susceptible to the potential difficulties associated with rapid growth and expansion.

We have grown rapidly over the last several years, including as a result of the Jagged Peak Acquisition. Our future success will depend, in part, upon our ability to manage this expanded business, which will pose substantial challenges for management, including challenges related to the management and monitoring of new operations and associated increased costs, complexity and responsibilities of our executive level personnel. We may also face increased scrutiny from governmental authorities as a result of the significant increase in the size of our business. Our operating results could be adversely affected if we do not successfully manage these challenges and there can be no assurance that we will be successful in managing our expanded business.

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, 2019, we had placed on production 478 gross (432.2 net) horizontal wells and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. Furthermore, certain of the new techniques we are adopting, such as well-spacing optimization and multi-well pad drilling, may impact the volumes of oil and gas that we ultimately recover and cause irregularities or interruptions in production due to the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established practices. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas, particularly to the extent that development in these areas requires the use of new drilling and completion techniques. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are worse than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity price declines, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

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

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

Our ability to use our net operating loss carryforwards and Jagged Peak's historic net operating loss carryforwards may be limited.

As of December 31, 2019, we had approximately $587.1 million of U.S. federal net operating loss carryforwards ("NOLs"), $535.3 million of which were incurred prior to January 1, 2018 and will begin to expire, if unused, in 2034, and $51.8 million of which were incurred on or after January 1, 2018 and will not expire and will be carried forward indefinitely. Utilization of these NOLs (as well as any historic NOLs of Jagged Peak) depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of such corporation's 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 occurs, utilization of the relevant corporation's NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of such corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate in effect during the month in which the ownership change occurs, subject to certain adjustments. Any unused annual limitation may be carried over to later years.

While we do not believe that the Jagged Peak merger resulted in an ownership change under Section 382 with respect to us, future issuances, sales and/or exchanges of our stock (including in connection with an exercise of the Exchange Right or other transactions beyond our control), taken together with prior transactions with respect to our stock and the acquisition of Jagged Peak, could cause us to undergo an ownership change. As a result, we cannot assure you that we have not or will not undergo an ownership change in 2020. However, even if we did have an ownership change in 2020, we do not believe that the resulting Section 382 annual limitation would prevent our utilization of our historic NOLs prior to their expiration, if applicable. We believe that the Jagged Peak merger resulted in an ownership change with respect to Jagged Peak, which, based on information currently available, may trigger a limitation (calculated as described above) on our ability to utilize any historic NOLs of Jagged Peak. This could cause some of Jagged Peak's NOLs incurred prior to January 1, 2018 to expire before we would be able to utilize them to reduce taxable income in future periods.

Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs and further limit our ability to use the historic NOLs of Jagged Peak, possibly resulting in future income tax expense that could adversely affect our operating results and cash flows.

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

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

Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity prices, interest rates and other risks associated with our business.

The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The CFTC has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.

The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or such transactions become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap executive facility.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

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

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

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions.

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

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on our ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- a cyber-attack resulting in the loss or disclosure of, or damage to, our or any of our customers' or suppliers' data or confidential information, which could harm our business by damaging our reputation, subjecting us to potential

financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps;

- a cyber-attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations;
- a cyber-attack by a nation state or non-state actor intended to disrupt the market for, or change the prices of, oil, natural gas and NGLs could reduce our revenues; and
- a cyber-attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues.

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

Actions of activist stockholders could cause us to incur substantial costs, divert management's attention and resources, and have an adverse effect on our business.

While we always welcome constructive input from our stockholders and regularly engage in dialogue with our stockholders to that end, activist stockholders may from time to time engage in proxy solicitations, advance stockholder proposals or otherwise attempt to impose changes or acquire control over us. If activist stockholder activities occur, our business could be adversely affected because responding to proxy contests and reacting to other actions by activist stockholders can be costly and time-consuming, disruptive to our operations and divert the attention of management and our employees. In addition, perceived uncertainties as to our future direction, strategy or leadership created as a consequence of activist stockholder initiatives may result in the loss of potential business opportunities, harm our ability to attract new investors, customers, employees, suppliers and other strategic partners, and cause our share price to experience periods of volatility or stagnation.

The Jagged Peak Acquisition may not be accretive, and may be dilutive, to our earnings per share, which may negatively affect the market price of shares on our Class A common stock.

In connection with the completion of the Jagged Peak Acquisition, we issued or distributed approximately 95.9 million shares of our Class A common stock. The issuance of these new shares of our Class A common stock could have the effect of depressing the market price of shares of our Class A common stock, through dilution of earnings per share or otherwise. Any dilution of, or delay of any accretion to, our earnings per share could cause the price of shares of our Class A common stock to decline or increase at a reduced rate.

In addition, as a result of the Jagged Peak Acquisition and the issuance of new shares of Class A common stock to former stockholders of Jagged Peak, stockholders who held shares prior to the Jagged Peak Acquisition will have less influence on the policies of the combined company than they currently have on our policies.

Our business relationships may be subject to disruption due to uncertainty associated with the Jagged Peak Acquisition, which could have a material adverse effect on our results of operations, cash flows and financial position following the Jagged Peak Acquisition.

Parties we do business with may experience uncertainty associated with the Jagged Peak Acquisition, including with respect to current or future business relationships following the Jagged Peak Acquisition. Our business relationships may be subject to disruption as customers, distributors, suppliers, vendors, landlords, joint venture partners and other business partners may attempt to delay or defer entering into new business relationships, negotiate changes in existing business relationships or consider entering into business relationships with other parties following the Jagged Peak Acquisition. These disruptions could have a material adverse effect on our results of operations, cash flows and financial position, as well as a material adverse effect on our ability to realize the expected cost savings and other benefits of the Jagged Peak Acquisition.

We have incurred and are expected to continue to incur significant transaction costs in connection with the Jagged Peak Acquisition, which may exceed anticipated costs.

We have incurred and are expected to continue to incur a number of non-recurring costs associated with completing the Jagged Peak Acquisition, combining our operations with Jagged Peak's operations and achieving desired synergies. These costs have been, and will continue to be, substantial. A substantial majority of non-recurring expenses have consisted and will consist of transaction costs and include, among others, fees paid to financial, legal, accounting and other advisors, employee retention, severance and benefit costs, and filing fees. We have also incurred and will continue to incur costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and other employment-related costs. We will continue to assess the magnitude of these costs, and additional unanticipated costs may be incurred in connection with the Jagged Peak Acquisition and the integration of the two companies' businesses. While we have assumed that a certain level of expenses would be incurred, there are many factors beyond our control that could affect the total amount or the timing of the expenses. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term, or at all. The costs described above and any unanticipated costs and expenses could have an adverse effect on our financial condition and operating results.

One of our directors, Mr. VanLoh, has significant duties with, and spends significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

One of our directors, Mr. VanLoh, holds positions of responsibility with other entities that are in the business of identifying and acquiring oil and natural gas properties. For example, Mr. VanLoh serves as the Chief Executive Officer of Quantum Energy Investment Partners ("Quantum"), which is in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties. The existing positions held by Mr. VanLoh may give rise to fiduciary or other duties that are in conflict with the duties he owes to us as a director. He may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which he is or may become affiliated. Due to these existing and potential future affiliations, he may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. He may also decide that certain opportunities are more appropriate for other entities with which he is affiliated, and as a result, he may elect not to present those opportunities to us. These conflicts may not be resolved in our favor.

Risks Related to our Common Stock

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

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

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

Holders of our Class A common stock and Class B common stock vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our certificate of incorporation. Upon the completion of the Jagged Peak Acquisition, our directors and executive officers held voting power over approximately 24.7% of our outstanding common stock. The existence of this significant insider ownership position may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

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

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

We have engaged in transactions and expect to continue to engage in transactions with related parties and affiliated companies. These transactions, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests.

For additional information regarding our related party transactions, see Note 13—Related Party Transactions to our consolidated financial statements included elsewhere in this Annual Report and, when filed with the SEC, the definitive proxy statement for our 2020 annual meeting of stockholders.

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

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

- a classified board of directors, with only approximately one-third of our board of directors elected each year;
- limitations on the removal of directors, including the requirement that a director may only be removed for cause and upon the affirmative vote of the holders of at least two-thirds of the outstanding shares of stock of the Company entitled to vote generally for the election of directors;
- the inability of our stockholders to call special meetings or act by written consent;
- the ability of our board of directors to adopt, alter or repeal our bylaws and the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained for stockholders to amend, alter or repeal our bylaws;
- the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained to amend, alter or repeal any provision of our certificate of incorporation;
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock. In addition, certain change of control events have the effect of accelerating any payments due under our Revolving Credit Agreement and the TRA, and could, in certain circumstances, accelerate payments required by the indentures governing our senior unsecured notes, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company. Please see "—In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA."

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

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any director or officer or other employee of ours arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us or any director or officer or other employee of ours that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. The exclusive forum provision would not apply to suits brought to enforce any liability or duty created by the Securities Act or the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. To the extent that any such claims may be based upon federal law claims, Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations promulgated thereunder. Furthermore, Section 22 of the Securities Act provides for concurrent federal and state court jurisdiction over actions under the Securities Act and the rules and regulations promulgated thereunder. Stockholders will not be deemed, by operation of Article 14 of the certificate of incorporation alone, to have waived claims arising under the federal securities laws and the rules and regulations promulgated thereunder.

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. In addition, there is uncertainty as to whether a court would enforce such provision. If a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

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

On August 26, 2019, we announced the initiation of quarterly cash dividends on our Class A common stock payable beginning with the third quarter of 2019. The decision to pay any future dividends, however, is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our results of operations, financial condition, liquidity, capital requirements, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. In addition, our debt agreements and the Parsley LLC Agreement place certain restrictions on Parsley LLC's ability to distribute cash to PE Unitholders (including to us to fund cash dividends to holders of Class A common stock). Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, or declare dividends at rates that are less than currently anticipated, either of which could reduce returns to our stockholders. Any elimination of or downward revision in our dividend payout could have a material adverse effect on the market price of our Class A common stock.

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

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

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

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

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

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

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

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

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

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

In these situations, our obligations under the TRA could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction costs a potential acquirer may attribute to satisfying such obligations. For example, if the TRA were terminated at December 31, 2019, the estimated termination payment would be approximately $135.2 million (calculated using a discount rate of LIBOR plus 3%, applied against an undiscounted liability of $275.6 million). The foregoing number is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the TRA.

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

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

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

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

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

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

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

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

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

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

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

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

Q-Jagged Peak Energy Investment Partners, LLC is a significant holder of our Class A common stock following completion of the Jagged Peak Acquisition.

Following the completion of the Jagged Peak Acquisition, Q-Jagged Peak Energy Investment Partners, LLC ("Q-Jagged Peak"), an affiliate of Quantum, owns approximately 17% of our Class A common stock, representing approximately 16% of our combined voting power. As a result, Q-Jagged Peak may be able to impact matters requiring stockholder approval. In addition, the existence of a large stockholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as Q-Jagged Peak continues to control a significant amount of our Class A common stock, it may continue to be able to impact matters requiring stockholder approval. In any of these matters, the interests of Q-Jagged Peak may differ or conflict with the interests of our other stockholders. In addition, Q-Jagged Peak and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business or of our significant existing or potential customers. Q-Jagged Peak 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 large stockholder.

Sales of substantial amounts of our common stock, by former Jagged Peak stockholders or otherwise, could depress the price of our Class A common stock.

Our stockholders may not wish to continue to invest in the additional operations of the combined company, or for other reasons may wish to dispose of some or all of their interests in the combined company, and as a result may seek to sell their shares of our common stock. Former Jagged Peak stockholders, including Q-Jagged Peak, may also seek to sell their shares of our Class A common stock delivered to them in merger, and the Merger Agreement contains no restriction on their ability to sell such shares.

In connection with the Jagged Peak Acquisition, we entered into a registration rights agreement (the "Registration Rights Agreement") with Q-Jagged Peak, pursuant to which we filed with the SEC a registration statement on Form S-3 registering for resale the shares of our Class A common stock issued to Q-Jagged Peak and may be required to conduct certain underwritten offerings upon Q-Jagged Peak's request. The Registration Rights Agreement also provides Q-Jagged Peak with customary piggyback registration rights.

In addition to sales by Q-Jagged Peak, other stockholders may also seek to sell shares of our Class A common stock held by them. These sales (or the perception that these sales may occur), coupled with the increase in the outstanding number of shares of our Class A common stock, may affect the market for, and the market price of, shares of our Class A common stock in an adverse manner. These sales might also make it more difficult for us to raise capital by selling equity or equity-related securities at a time and price that we otherwise would deem appropriate.

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, 2019, our acreage position consisted of 246,405 gross (191,179 net) acres, and approximately 85% of our net acres were held by production. As of December 31, 2019, we had interests in 753 gross (578.0 net) producing horizontal wells, of which 597 gross (558.9 net) horizontal wells were operated by us, and interests in 1,199 gross (765.3 net) producing vertical wells, of which 872 gross (723.1 net) vertical wells were operated by us.

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

Core Area Descriptions

We group our assets into two separate areas, the Midland Basin and the Delaware Basin, based on each area's similar geologic, economic and technical requirements.

Midland Basin

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

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

As of December 31, 2019, we held 202,773 gross (149,615 net) acres in our Midland Basin area. Approximately 83% of our net acreage in this area is held by production. We had interests in 616 gross (470.5 net) producing horizontal wells in the Midland Basin as of December 31, 2019, of which 484 gross (452.1 net) horizontal wells were operated by us. We also had interests in 1,131 gross (752.8 net) producing vertical wells in the Midland Basin.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2019, we have placed on production 478 gross (432.2 net) horizontal wells in the Midland Basin. The table below summarizes the horizontal wells placed on production in the Midland Basin during the periods indicated:

Year ended December 31,(1)(2)					
2019		2018		2017	
Gross	Net	Gross	Net	Gross	Net
121	114.2	132	127.9	96	89.5

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

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

Delaware Basin

From the mid-Pennsylvanian period to the early Permian period, the Delaware Basin was a slowly subsiding area that was characterized by shallow marine shales and limestone. Influxes of clastic sands generally occurred as turbidite deposits formed during periodic sea-level changes. Records indicate a rapid deepening of the Delaware Basin relative to the emergent Central Basin Platform, during the early Permian period. Marine shale deposition continued to dominate the basin during this period. Episodic pulses of carbonate and clastic debris and density flows punctuated the shale deposition and eventually became significant reservoirs. The middle Permian period was dominated by large changes in sea level resulting in alternating phases of carbonate dominated and clastic dominated sedimentation, which are now 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, 2019, we held 43,632 gross (41,564 net) acres in our Delaware Basin area. Approximately 92% of our net acreage in this area is held by production; however, we hold mineral interests in a significant portion of our Delaware Basin leasehold acreage, which ensures our ability to continue producing from this area. As of December 31, 2019, we had interests in 137 gross (107.5 net) producing horizontal wells in the Delaware Basin, of which 113 gross (106.9 net) horizontal wells were operated by us. We also had interests in 68 gross (12.5 net) producing vertical wells in the Delaware Basin.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2019, we have placed on production 94 gross (90.3 net) horizontal wells in the Delaware Basin. The table below summarizes the horizontal wells placed on production in the Delaware Basin during the periods indicated:

Year ended December 31,(1)(2)					
2019		2018		2017	
Gross	Net	Gross	Net	Gross	Net
24	23.1	43	41.9	21	19.9

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

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

Production Status

For the year ended December 31, 2019, our average daily net sales from our wells on our Midland Basin acreage was 114,902 Boe/d, of which 59% was from oil, 18% was from natural gas and 23% was from NGLs. Over the same period, our average daily net sales from our wells on our Delaware Basin acreage was 25,704 Boe/d, of which 75% was from oil, 11% was from natural gas and 14% was from NGLs.

Operational Facilities

Our land-based oil and natural gas processing facilities are typical of those found in the Permian Basin. Our facilities at well locations or centralized lease locations include storage tank batteries, oil/natural gas/water separation equipment, and pumping units. In addition, throughout our acreage, we own and operate facilities with significant water sourcing, gathering transfer, and disposal capacity.

Recent Activity

During the year ended December 31, 2019, we incurred costs of approximately $956.9 million and $194.7 million for our Midland Basin and Delaware Basin horizontal drilling and completions, respectively. We incurred costs of approximately $5.5 million for vertical drilling, completions and recompletions. We also incurred costs of approximately $215.8 million associated with facilities and infrastructure.

The amount and timing of our future capital expenditures are 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 working interest owners.

Production, Price and Cost Data

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,		
	2019	2018	2017
Average daily production volume(1):			
Oil (Bbls/d)	86,751	69,468	44,904
Natural gas (Mcf/d)	142,282	102,370	63,907
Natural gas liquids (Bbls/d)	30,142	22,885	12,362
Total (Boe/d)	140,608	109,416	67,923
Average realized prices(2):			
Oil (per Bbl)	$ 55.50	$ 60.59	$ 48.95
Natural gas (per Mcf)	0.71	1.37	2.43
Natural gas liquids (per Bbl)	14.17	27.21	22.87
Average price per Boe	37.99	45.44	38.80
Average production costs (per Boe)(3):			
Lease operating expenses	$ 3.45	$ 3.61	$ 4.12
Transportation and processing costs	0.80	0.82	—
Production and ad valorem taxes:			
Production	1.80	2.25	1.98
Ad valorem	0.63	0.46	0.43
Total	$ 2.43	$ 2.71	$ 2.41
Depreciation, depletion and amortization	$ 15.49	$ 14.64	$ 14.21

(1) Natural gas and NGLs sales and production volumes for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(2) Refer to “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Production Revenues” for average realized prices after the effects of our realized commodity hedging transactions.

(3) Average production costs per Boe for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

For additional information, see “Item 1. Business—Oil and Natural Gas Production and Operations—Production and Price History,” which is incorporated herein by reference.

Evaluation and Review of Proved Reserves

Estimates of our proved reserves as of December 31, 2019, 2018 and 2017 were based on evaluations prepared by our internal staff of petroleum engineers and audited by NSAI. We have no oil and natural gas reserves from non-traditional sources. Additionally, we do not provide optional disclosure of probable or possible reserves. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis.

Reserve estimation procedures. We maintain an internal staff of petroleum engineers and geoscience professionals (the “Reserves Group”) to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. We have established internal controls over reserve estimation processes and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC requirements. These controls include oversight of the reserves estimation reporting process by our Vice President—Reservoir Engineering and Planning who reports directly to our Executive Vice President—Chief Operating Officer as well as annual external audits of our proved reserves by NSAI.

In addition, we maintain a Reserves Planning and Disclosure Committee that is chaired by our Vice President—Reservoir Engineering and Planning. The Reserves Planning and Disclosure Committee is also comprised of certain members of our management team and other employees relevant to the reserves estimation process. The Reserves Planning and Disclosure Committee meets on a regular basis to review our reserves estimates, advise management of any material reserve adjustments and review and approve our annual reserve estimates filed with the SEC and any other public disclosure of reserve estimates. We also maintain a Reserves Committee of our board of directors (the “Reserves Committee”) that meets regularly to, among other things, review our reserves estimates, advise our board of directors on any material reserve adjustments, review and approve our annual reserves estimates filed with the SEC and periodically interface with our independent, third-party petroleum consulting firm.

The reserve estimates are summarized in reserve reconciliations that quantify reserve changes from the previous year end as revisions of previous estimates, purchases of minerals-in-place, improved recovery, extensions and discoveries, production and sales of minerals-in-place. All reserve estimates, material assumptions and inputs used in reserve estimates and significant changes in reserve estimates are reviewed for engineering and financial appropriateness and compliance with SEC and GAAP standards by the Reserves Group, in consultation with our accounting and financial management personnel. Annually, our Executive Vice President—Chief Operating Officer, Vice President—Reservoir Engineering and Planning and the Reserves Planning and Disclosure Committee review the reserve estimates and any differences with the reserve auditors on a consolidated basis before these estimates are approved by the Reserves Committee and our board of directors.

Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical information used in reserve estimation models, including oil, natural gas and NGLs prices, production costs, transportation costs, future capital expenditures and our net ownership percentages are obtained from other departments. Internally, we conduct testing with respect to such non-technical inputs.

Proved reserves audits. The proved reserve audits performed by NSAI for the year ended December 31, 2019, in the aggregate, represented 100% of our year-end 2019 proved reserves, and 100% of our year-end 2019 associated pre-tax present value of proved reserves discounted at ten percent.

NSAI follows the general principles set forth in the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information” promulgated by the Society of Petroleum Engineers (the “SPE”). A reserve audit as defined by the SPE is not the same as a financial audit. The SPE’s definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been presented in conformity with the 2007 SPE publication entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information.”
- The estimation of reserves is an imprecise science due to the many unknown geologic and reservoir factors that cannot be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by a company is reasonable.

- The methods and procedures used by a company and the reserve information furnished by a company must be reviewed in sufficient detail to permit the reserve auditor, in its professional judgment, to express an opinion as to the reasonableness of the reserve information. The auditing procedures require the reserve auditors to prepare their own estimates of reserve information for the audited properties.

In conjunction with the audit of our proved reserves and associated pre-tax present value of proved reserves discounted at 10%, the Reserves Group provided to NSAI its external and internal engineering and geoscience technical data and analyses. NSAI accepted without independent verification the accuracy and completeness of the historical information and data furnished by us with respect to ownership interest, oil and natural gas production, well test data, commodity prices, operating and development costs, and any agreements relating to current and future operations of the properties and sales of production. However, if in the course of its evaluations something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

In the course of its evaluations, NSAI prepared, for all of the audited properties, its own estimates of our proved reserves and the pre-tax present values of such reserves discounted at 10%. NSAI reviewed its audit differences with us, and, as necessary, held meetings with us to review additional reserves work performed by our technical teams and any updated performance data related to the proved reserve differences. Such data was incorporated, as appropriate, by both parties into the proved reserve estimates. NSAI's estimates, including any adjustments resulting from additional data, of those proved reserves and the pre-tax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease basis, some of our estimates were greater than those of the reserve auditors and some were less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present values of such reserves discounted at 10% are reasonable and that its audit objectives have been met, NSAI will issue an unqualified audit opinion. At the conclusion of the audit process, it was NSAI's opinion, as set forth in its audit letter, which is included as an exhibit to this Annual Report, that our estimates of our proved oil and natural gas reserves and associated pre-tax present values discounted at 10% are, in the aggregate, reasonable and have been prepared in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE.

Qualifications of proved reserves preparers and auditors. The Reserves Group is staffed by petroleum and geoscience professionals with extensive industry experience and the process is managed by our Vice President—Reservoir Engineering and Planning, the technical person primarily responsible for overseeing the preparation of all of our reserve estimates. The qualifications of our Vice President—Reservoir Engineering and Planning include over 17 years of reservoir and operations experience. She holds a Bachelor of Science in Petroleum Engineering and a Master of Science in Global Energy Management. She is also a member of multiple professional industry organizations. Our Vice President—Reservoir Engineering and Planning reports directly to our Executive Vice President—Chief Operating Officer, whose qualifications include over 15 years of reservoir and operations experience. He graduated with a Bachelor of Science in Petroleum Engineering and a Master of Business Administration and is a member of various professional industry organizations. Our Reserves Group has an average of approximately 19 years of industry experience per person.

As described above, following the preparation of our reserves estimates, these estimates are audited for their reasonableness by NSAI. NSAI provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. The technical person primarily responsible for auditing our reserves estimates has been a practicing consulting petroleum engineer at NSAI since 1998 and has over 39 years of practical experience in petroleum engineering and meets or exceeds the education, training and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE.

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." 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. We believe that 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.

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 target zone being evaluated or in an analogous target zone. 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.

The following table sets forth the combined production volumes and reserves by area (in MBoe):

	Year Ended December 31, 2019	December 31, 2019	
	Production Volumes	Proved Developed Reserves	Proved Reserves
Midland Basin	41,940	319,571	503,253
Delaware Basin	9,382	62,173	89,081
Total	51,322	381,744	592,334

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

	December 31,		
	2019	2018	2017
Proved developed reserves[(1)]:			
Oil (MBbls)	206,849	170,526	119,591
Natural gas (MMcf)	472,160	358,733	240,337
Natural gas liquids (MBbls)	96,202	81,000	49,751
Combined (MBoe)	381,744	311,315	209,399
Proved undeveloped reserves[(1)]:			
Oil (MBbls)	119,614	123,920	128,940
Natural gas (MMcf)	237,082	213,305	211,366
Natural gas liquids (MBbls)	51,462	50,933	42,881
Combined (MBoe)	210,590	210,404	207,048
Proved reserves[(1)]:			
Oil (MBbls)	326,463	294,446	248,531
Natural gas (MMcf)	709,242	572,038	451,703
Natural gas liquids (MBbls)	147,664	131,933	92,632
Combined (MBoe)	592,334	521,719	416,447

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(1) Natural gas and NGLs reserves for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

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 will 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."

Proved Reserves

As of December 31, 2019, our proved reserves were composed of 326,463 MBbls of oil, 709,242 MMcf of natural gas and 147,664 MBbls of NGLs, for a total of 592,334 MBoe.

The following table summarizes the changes in our proved reserves during the year ended December 31, 2019 (in MBoe):

Balance, December 31, 2018	521,719
Purchases of reserves in place	554
Divestures of reserves in place	(3,076)
Extensions and discoveries	138,750
Revisions of previous estimates	(14,291)
Production	(51,322)
Balance, December 31, 2019	592,334

Changes in our proved reserves during the year ended December 31, 2019 primarily resulted from the following significant factors:

Purchases of reserves. During the year ended December 31, 2019, we added 554 MBoe of proved reserves, primarily as a result of the acquisition of incremental working interests in properties and undeveloped acreage in the Midland Basin.

Divestiture of reserves. During the year ended December 31, 2019, we divested 3,076 MBoe of proved reserves in the Midland Basin.

Extensions and discoveries. Extensions and discoveries of 138,750 MBoe during the year ended December 31, 2019 resulted primarily from our successful horizontal drilling program in the Midland Basin and Delaware Basin, of which approximately 48% is associated with proved undeveloped locations.

Revisions of previous estimates. During the year ended December 31, 2019, we experienced total negative revisions of previous estimates of 14,291 MBoe. The main driver of the these revisions was the reclassification of certain PUD reserves to unproved reserves, which resulted in a 23,686 MBoe downward revision to previous estimates related to the removal of reserves for proved undeveloped locations determined to be outside of our five-year capital expenditure plan. Other drivers included positive revisions to well performance of 6,683 MBoe and positive revisions associated with working interest and operating expenses of 4,816 MBoe. A negative revision of 2,103 MBoe was attributable to a price adjustment due to a decrease in pricing as calculated using SEC guidelines.

Production. During the year ended December 31, 2019, our production volumes were 51,322 MBoe resulting in a corresponding decrease in our proved reserves.

As of December 31, 2019, 1,405 MBoe, or less than one percent of our total proved reserves, were classified as proved developed non-producing.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2019, our proved undeveloped reserves were composed of 119,614 MBbls of oil, 237,082 MMcf of natural gas and 51,462 MBbls of NGLs, for a total of 210,590 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes the changes in our PUDs during the year ended December 31, 2019 (in MBoe):

Balance, December 31, 2018	210,404
Purchases of reserves	95
Divestiture of reserves	(1,562)
Extensions and discoveries	65,933
Revisions of previous estimates	(19,336)
Transfers to proved developed	(44,944)
Balance, December 31, 2019	210,590

Changes in our PUDs during the year ended December 31, 2019 primarily resulted from the following significant factors:

Purchases of reserves. During the year ended December 31, 2019, we added 95 MBoe of PUDs, primarily as a result of the acquisition of undeveloped acreage in the Midland Basin.

Divestiture of reserves. During the year ended December 31, 2019, we divested 1,562 MBoe of PUDs, all of which were in the Midland Basin.

Extensions and discoveries. Extensions and discoveries of 65,933 MBoe during the year ended December 31, 2019 resulted primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year.

Revisions of previous estimates. During the year ended December 31, 2019, we experienced total negative revisions to previous PUD reserve estimates of 19,336 MBoe. The main driver of this adjustment was the reclassification of certain PUD reserves to unproved reserves, which accounted for a 23,686 MBoe downward revision to previous estimates associated with the removal of reserves for locations determined to be outside of our five-year capital expenditure plan. We also experienced positive revisions of 7,465 MBoe associated with changes to our type curves and working interests and negative revisions of 3,115 MBoe associated with changes in lease operating expenses, pricing and capital expenditures.

Transfers to proved developed. During the year ended December 31, 2019, we transferred 44,944 MBoe of PUDs to proved developed.

Capital Development Plan

At the end of each year, we schedule a five-year capital expenditure plan based on our best available data and financial feasibility at the time the plan is developed. In connection with the adoption of our capital expenditure plan, we prepare a field-level plan that includes the timing, location and capital commitment of wells that we expect to be drilled. Our capital expenditure plan includes only PUD reserves that we are reasonably certain, based on SEC pricing at the time of adoption, will be drilled within five years of booking based upon management's evaluation of a number of qualitative and quantitative factors, including: estimated risk-based returns; estimated well density; cost forecasts; recent drilling, recompletion or re-stimulation results and well performance; anticipated availability of services, equipment, supplies and personnel; seasonal weather; and changes in drilling and completion techniques and technology. Our PUD reserves do not include reserves associated with non-operated properties. This process is intended to ensure that PUD reserves are only booked for locations where a final investment decision has been made by us. Our five-year development plan generally does not contemplate a uniform conversion of PUD reserves in all of its producing areas or over the five-year period covered by such plan. Our board of directors annually reviews our expenditure plan and approves the capital budget for the first year of the development plan, including with respect to any material changes made to the plan during the prior year as a result of the factors discussed below.

Following the adoption of our development plan based on information available at the time of such adoption, we review and, if the circumstances warrant, may revise the capital expenditure plan throughout the year and modify the plan after evaluating a number of factors, including: operational results; decreases in, or volatility of commodity prices; estimated risk-based returns; cost and availability of services, equipment and resources; acquisition and divestiture activity; and our current and projected financial condition and liquidity. Based on the foregoing review, we update our development plan each quarter to reflect any necessary changes, and such changes are then reviewed and approved by our senior management. Any material deviations from our capital expenditure budget and development plan are discussed with the Reserves Committee and our board of directors.

Annually and periodically as circumstances warrant, the Reserves Group conducts a detailed review on a lease-by-lease basis to assess whether potential PUD locations remain reasonably certain to be drilled on a timely basis within five years from their initial booking. If, upon completion of such review, the Reserves Group determines that any of the potential PUD locations that it identified may be unlikely to be transferred from PUDs to proved developed reserves within their anticipated development timeline, such locations are then reviewed by our senior management to determine whether we expect to have sufficient committed capital and other resources necessary to commit to the proposed development plan. If our senior management determines that a proposed PUD location is not reasonably certain to be drilled within five years of initial booking or we do not have sufficient committed capital to pursue its development, that PUD location is excluded from our subsequent estimation of our proved reserves and re-classified to non-proved reserve categories.

Costs incurred relating to the development of locations that were classified as PUDs at December 31, 2018 were approximately $457.2 million during the year ended December 31, 2019. Additionally, during 2019, we spent approximately $640.1 million drilling and completing other in-field wells which were not classified as proved as of December 31, 2018. Estimated future development costs relating to the development of PUDs at December 31, 2019 were projected to be approximately $793.6 million in 2020. We intend to finance such development costs with cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement. As of December 31, 2019, all of our PUD drilling locations were scheduled to be drilled within five years of their initial booking.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this Annual Report and the audit letter relating to the proved reserve report as of December 31, 2019, which is included as an exhibit to this Annual Report.

Developed and Undeveloped Acreage

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

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Midland Basin	168,877	123,457	33,896	26,158	202,773	149,615
Delaware Basin	40,189	38,347	3,443	3,217	43,632	41,564
Total	209,066	161,804	37,339	29,375	246,405	191,179

(1) Developed acreage is acreage spaced or assigned to productive wells, excluding undrilled acreage held by production under the terms of the applicable lease.

(2) Undeveloped acreage is acreage 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. Most 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, generally the leases are held with additional development every 60 to 180 days until the entire lease is held by production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2019, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2020		2021		2022		2023		2024		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	11,360	7,539	9,292	4,365	6,771	5,384	470	244	6,552	6,451	2,311	1,906
Delaware Basin	880	880	640	530	1,923	1,806	—	—	—	—	—	—
Total	12,240	8,419	9,932	4,895	8,694	7,190	470	244	6,552	6,451	2,311	1,906

As of December 31, 2019, of the total net PUD reserves associated with the expiring acreage set forth in the table above, an immaterial amount of those net PUD reserves are associated with drilling locations scheduled to be drilled after expiration of the applicable leasehold.

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 any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Horizontal:						
Development Wells[1]:						
Productive[2]	155	147	162	157	126	119
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive[2]	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Vertical:						
Development Wells[1]:						
Productive[2]	2	2	2	2	2	2
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive[2]	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total:						
Productive[2]	157	149	164	159	128	121
Dry holes	—	—	—	—	—	—
	157	149	164	159	128	121

(1) Includes extension wells.

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

As of December 31, 2019, in the Midland Basin, we had 20 gross (18.4 net) horizontal wells in the process of being drilled and 23 (20.9 net) horizontal wells awaiting hydraulic fracturing procedures that, in each case, are not reflected in the above table. In the Delaware Basin, we had 3 gross (3.0 net) horizontal wells in the process of being drilled that are not reflected in the above table. As of December 31, 2019, there were no horizontal wells in the Delaware Basin awaiting hydraulic fracturing procedures.

For additional information regarding our productive wells, see “Item 1. Business—Oil and Natural Gas Prices and Operations—Productive Wells,” which is incorporated herein by reference.

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 obtain title opinions covering the properties prior to entering into a purchase and sale agreement. At the time 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 commencing 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 our use of or affect the 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, 2019, we leased corporate office space in Austin, Texas at 303 Colorado Street, where our corporate headquarters is located, and at certain other locations in downtown Austin. We also owned field operation facilities in Midland and Fort Stockton, Texas. We believe that our facilities are adequate for our current operations.

During 2017, we entered into an agreement with a third party to lease commercial office space in a building being constructed at 300 Colorado Street, Austin, Texas. Upon its completion, we expect to move our corporate headquarters to this location.

Transportation and Delivery Commitments

For information regarding the transportation of our oil and natural gas, production and our contractual commitments related thereto, see “Item 1. Business—Oil and Natural Gas Production and Operations—Transportation and Delivery Commitments,” which is incorporated herein by reference.

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.

Litigation Related to the Jagged Peak Acquisition

Following our and Jagged Peak's filing with the SEC of a joint proxy statement/prospectus (the "Jagged Peak Acquisition Proxy Statement") for the solicitation of proxies in connection with the special meetings to be held in connection with the Jagged Peak Acquisition, six purported stockholders of Jagged Peak (the "Jagged Peak Plaintiffs") filed separate complaints (including several putative class actions complaints, on behalf of themselves and all owners of Jagged Peak's common stock, other than defendants and related or affiliated persons) against Jagged Peak and the directors of Jagged Peak. The six complaints (collectively referred to as the "Stockholder Actions") are captioned as follows: Eric Sabatini v. Jagged Peak Energy Inc. et al., Case No. 1:19-cv-02114 (D. Del.); Jean-Pierre Enguehard v. Jagged Peak Energy, Inc. et al., Case No. 2019-cv-34328 (Distr. Ct., Denver, CO) (the "Enguehard Action"); Kelly Small v. Jagged Peak Energy Inc. et al., Case No. 1:19-cv-10698 (S.D.N.Y.); Sherrie Wynne v. Jagged Peak Energy Inc. et al., Case No. 1:19-cv-03281 (D. Colo.); Mark Prinzel v. Jagged Peak Energy Inc. et al., Case No. 1:19-cv-10886 (S.D.N.Y.); and Stephen Bushansky v. Jagged Peak Energy Inc. et al., Case No. 1:19-cv-3433 (D. Colo.).

The Stockholder Actions alleged that, among other things, the Jagged Peak Acquisition Proxy Statement failed to disclose certain allegedly material information in violation of Section 14(a) and Section 20(a) of the Exchange Act, as well as Rule 14a-9 under the Exchange Act. The Enguehard Action further alleged that the directors of Jagged Peak failed to fulfill their fiduciary duties in connection with the Jagged Peak Acquisition by purportedly initiating a process to sell Jagged Peak in a transaction that undervalues Jagged Peak. The complaints sought injunctive relief enjoining the Jagged Peak Acquisition and damages and costs, among other remedies.

On January 2, 2020, we and Jagged Peak each filed a Current Report on Form 8-K that supplemented the Jagged Peak Acquisition Proxy Statement with certain disclosures responsive to allegations made by the Jagged Peak Plaintiffs. Following these filings, all of the Stockholder Actions were voluntarily dismissed by the Jagged Peak Plaintiffs.

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

Market Information

Our Class A common stock trades on the NYSE under the symbol "PE."

Stockholders

On February 19, 2020, we had approximately 50 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 19, 2020, we had 38 holders of record of our Class B common stock.

Dividends

During the third quarter of 2019, our board of directors initiated our first quarterly dividend, payable on issued and outstanding shares of Class A common stock, and, in its capacity as the managing member of Parsley LLC, a corresponding distribution from Parsley LLC to the PE Unitholders. The portion of the Parsley LLC distribution attributable to PE Units held by Parsley Energy, Inc. was used to fund the quarterly dividend on issued and outstanding shares of Class A common stock. As described hereinafter, as the context requires, dividends paid to holders of Class A common stock and distributions paid to PE Unitholders (other than Parsley Energy, Inc.) may be referred to collectively as "dividends."

Although we intend to continue to pay a quarterly dividend, the decision to pay future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our results of operations, financial condition, liquidity, capital requirements, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. In addition, our debt agreements and the Parsley LLC Agreement place certain restrictions on Parsley LLC's ability to distribute cash to PE Unitholders (including to us to fund cash dividends to holders of Class A common stock). For additional information regarding our historic dividends practice, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity—Dividends."

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table sets forth information with respect to our repurchases of shares of Class A common stock during the quarter ended December 31, 2019.

Period	Total number of shares purchased [(1)]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
10/1/2019 - 10/31/2019	259	$ 15.18	—	$ —
11/1/2019 - 11/30/2019	—	$ —	—	$ —
12/1/2019 - 12/31/2019	188	$ 17.24	—	$ —
Total	447	$ 16.05	—	$ —

(1) Consists of shares of Class A common stock repurchased from employees in order for the employee to satisfy tax withholding payments related to stock-based awards that vested during the period.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the period covered by this Annual Report that were not previously reported in a Current Report on Form 8-K or Quarterly Report on Form 10-Q.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical consolidated financial data for the periods and as of the periods indicated. The following selected 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,				
	2019	2018	2017	2016	2015
	(in thousands, except per share data)				
Revenues	$ 1,958,814	$ 1,826,431	$ 967,044	$ 457,773	$ 266,474
Operating expenses	1,421,544	1,198,556	714,575	426,745	374,969
Operating income (loss)	537,270	627,875	252,469	31,028	(108,495)
Other (expenses) income	(265,415)	(76,431)	(122,841)	(137,369)	11,709
Income (loss) before income taxes	271,855	551,444	129,628	(106,341)	(96,786)
Income tax (expense) benefit	(61,437)	(105,475)	(5,708)	17,424	23,755
Net income (loss)	210,418	445,969	123,920	(88,917)	(73,031)
Less: Net (income) loss attributable to noncontrolling interest holders	(35,206)	(76,842)	(17,146)	14,735	22,547
Net income (loss) attributable to Parsley Energy, Inc. Stockholders	$ 175,212	$ 369,127	$ 106,774	$ (74,182)	$ (50,484)
Net income (loss) per common share:					
Basic	$ 0.63	$ 1.36	$ 0.44	$ (0.46)	$ (0.45)
Diluted	$ 0.63	$ 1.35	$ 0.42	$ (0.46)	$ (0.45)
Weighted average shares:					
Basic	279,636	272,226	240,733	161,793	111,271
Diluted	280,172	272,884	296,512	161,793	111,271
Dividends declared per share	$ 0.06	$ —	$ —	$ —	$ —
Average daily production volume(1):					
Oil (Bbls/d)	86,751	69,468	44,904	25,596	13,170
Natural gas (Mcf/d)	142,282	102,370	63,907	36,794	28,326
Natural gas liquids (Bbls/d)	30,142	22,885	12,362	6,530	4,110
Total (Boe/d)	140,608	109,416	67,923	38,257	22,003
Average realized prices(2):					
Oil (per Bbl)	$ 55.50	$ 60.59	$ 48.95	$ 41.34	$ 44.89
Natural gas (per Mcf)	0.71	1.37	2.43	2.30	2.57
NGLs (per Bbl)	14.17	27.21	22.87	16.01	15.79
Average price per Boe	37.99	45.44	38.80	32.60	33.13
Consolidated statements of cash flows data:					
Net cash provided by (used in):					
Operating activities	$ 1,286,279	$ 1,218,974	$ 690,750	$ 230,342	$ 173,429
Investing activities	(1,400,799)	(1,594,036)	(3,456,860)	(1,885,366)	(427,165)
Financing activities	(27,957)	(15,911)	3,183,630	1,447,470	547,409
Consolidated balance sheet data:					
Cash, cash equivalents, restricted cash and short-term investments	$ 20,739	$ 163,216	$ 703,472	$ 136,669	$ 344,223
Total assets	9,856,214	9,391,363	8,793,198	3,938,782	2,505,100
Long-term debt	2,182,832	2,181,667	2,179,525	1,041,324	546,832
Total equity	6,522,648	6,319,735	5,880,706	2,430,306	1,586,641

(1) Natural gas and NGLs sales and production volumes for the years ended December 31, 2019 and 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(2) Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Production Revenues" for average realized prices after the effects of our realized commodity hedging transactions.

Non-GAAP Financial Measures

PV-10

PV-10 is a non-GAAP financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net reserves. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such companies.

The following table provides a reconciliation of PV-10 to the GAAP financial measure of Standardized Measure as of December 31, 2019:

	As of December 31, 2019 (in millions)
Standardized Measure	$ 4,962.5
Present value of future income tax discounted at 10%	693.3
PV-10 of proved reserves	$ 5,655.8

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 financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." This section of this Form 10-K generally discusses 2019 and 2018 items and year-to-year comparisons between 2019 and 2018. Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in "Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018. 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.

Overview

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

Our sole material asset as of December 31, 2019 consisted of 281,241,443 PE Units and, as the sole managing member, we hold a controlling equity interest in Parsley LLC and manage the business and affairs of Parsley LLC and its subsidiaries. We consolidate the financial and operating results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interests in Parsley LLC held by PE Unitholders (other than Parsley Energy, Inc.).

Our Properties

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

	Developed Acreage		Undeveloped Acreage		Total Acreage	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	168,877	123,457	33,896	26,158	202,773	149,615
Delaware Basin	40,189	38,347	3,443	3,217	43,632	41,564
Total	209,066	161,804	37,339	29,375	246,405	191,179

Our identified drilling locations, as of December 31, 2019, were in Upton, Reagan, Midland, Howard, Martin and Glasscock Counties, Texas, in the Midland Basin, and Pecos and Reeves Counties, Texas, in the Delaware Basin.

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

	Vertical Wells		Horizontal Wells		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	859	710.6	484	452.0	1,343	1,162.6
Delaware Basin	13	12.5	113	106.9	126	119.4
Total	872	723.1	597	558.9	1,469	1,282.0

As of December 31, 2019, we held an interest in 1,952 gross (1,343.3 net) wells, including wells that we did not operate. As of December 31, 2019, we owned an immaterial number of productive wells related to the production of natural gas.

From the commencement of our horizontal drilling program in 2013 through December 31, 2019, we have placed on production 478 gross (432.2 net) horizontal wells in the Midland Basin and 94 gross (90.3 net) horizontal wells in the Delaware Basin. The table below summarizes the horizontal wells placed on production during the periods indicated:

	Year Ended December 31,			
	2019		2018	
Area	Gross	Net	Gross	Net
Midland Basin	121	114.2	132	127.9
Delaware Basin	24	23.1	43	41.9
Total	145	137.3	175	169.8

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;
- returns on capital invested; and
- certain unit costs.

Sources of Our Revenues

Our production 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, and do not include the effects of derivatives. Our production revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table presents the breakdown of our production revenues for the periods indicated:

	Year Ended December 31,	
	2019	2018
Oil sales	90%	84%
Natural gas sales	2%	3%
Natural gas liquids sales	8%	13%

Other revenues include fees from third parties, including working interest owners in our operated wells, and fees relating to our midstream operations, as well as water, easement and other surface use fees charged by Parsley Minerals, LLC to third parties. During the year ended December 31, 2018, Other revenues also included drilling service fees charged by Pacesetter Drilling, LLC ("Pacesetter") to third parties for drilling services.

Production Volumes

The following table presents historical production volumes for our properties for the periods indicated:

	Year Ended December 31,	
	2019	2018
Oil (MBbls)	31,664	25,356
Natural gas (MMcf)	51,933	37,365
Natural gas liquids (MBbls)	11,002	8,353
Total (MBoe)	51,322	39,937
Average net production (Boe/d)	140,608	109,416

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 the development of our properties as well as through 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

Historically, oil, natural gas and NGLs prices have been extremely volatile, and we expect this volatility to continue. Because our production consists primarily of oil, our production revenues are more sensitive to fluctuations in the price of oil than they are to fluctuations in the price of natural gas or NGLs.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we enter into derivative arrangements for a portion of our production, with an emphasis on our oil production. By removing a 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 the relevant periods. 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 differ from our historical hedging strategy. We are not under an obligation to hedge a specific portion of our oil, natural gas or NGLs production. See *Note 4—Derivative Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for details regarding the volumes and terms of our derivative instruments as of December 31, 2019.

We will have recognized the following cumulative losses in the line item (*Loss) gain on derivatives* on our consolidated statements of operations from net premiums paid or deferred on options that will settle during the following periods (in thousands):

Q1 2020	$	(14,639)
Q2 2020		(16,236)
Q3 2020		(13,990)
Q4 2020		(13,990)
	$	(58,855)

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.

Transportation and processing costs. Transportation and processing costs represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. Due to the adoption of ASC 606, we now report such costs separately. Refer to *Note 3—Revenue from Contracts with Customers* in our consolidated financial statements for additional discussion.

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. 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.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas.

General and administrative expenses. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our office facilities, costs of managing our production and development operations (including numerous software applications), audit and other fees for professional services and legal compliance.

Exploration and abandonment costs. Exploration and abandonment costs primarily include leasehold abandonment and impairment costs and geological and geophysical costs incurred**.**

(Loss) gain on derivatives. 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 our 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 through offerings of fixed-rate senior unsecured notes and borrowings from our floating-rate Revolving Credit Agreement. As a result, we incur interest expense that is affected by our financing decisions and may be affected by fluctuations in interest rates.

Impairment of Proved Oil and Natural Gas Properties

Proved oil and natural gas properties are reviewed for impairment periodically 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 natural gas properties and compare the undiscounted cash flows to the carrying amount of the oil and natural 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 natural gas properties to estimated fair value.

Given the volatility of commodity prices in recent years and their impact on our estimated future cash flows, we periodically review our proved oil and natural gas properties for impairment. During each of the years ended December 31, 2019 and 2018, we did not recognize an impairment of any of our proved oil and natural gas properties. At December 31, 2019, in our significant fields that comprise 100% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and natural gas properties by an average of 59% and individually by a minimum of 47%. At December 31, 2018, in our significant fields that comprise 100% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and natural gas properties by an average of 78% and individually by a minimum of 73%.

The key assumptions used to determine our expected undiscounted future cash flows include, but are not limited to, future commodity prices, price differentials, future production estimates, estimated future capital expenditures and estimated future operating expenses. All inputs in the undiscounted future cash flow estimate, except commodity price estimates, remained relatively consistent from December 31, 2018 to December 31, 2019. We evaluate future commodity pricing for oil and NGLs based on five-year NYMEX WTI futures prices, which increased from December 31, 2018 to December 31, 2019, and future commodity pricing for natural gas based on five-year NYMEX Henry Hub futures prices, which decreased from December 31, 2018 to December 31, 2019. In terms of the reduction in value of undiscounted cash flows from December 31, 2018 to December 31, 2019, 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. There is a significant degree of uncertainty with respect to 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 or 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, 2019, however, would not have resulted in an impairment of any of our proved oil and natural gas properties.

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

Jagged Peak Acquisition

On January 10, 2020, we completed the Jagged Peak Acquisition. For additional information, see "Item 1. Business—Recent Events—Jagged Peak Acquisition."

4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes

On February 11, 2020, Parsley LLC and Finance Corp. issued $400.0 million aggregate principal amount of 2028 Notes, resulting in net proceeds to us, after deducting estimated fees and expenses, of approximately $395.2 million. We intend to use such net proceeds and borrowings under the Revolving Credit Agreement to redeem all of the 2024 Notes. For additional information, see "Item 1. Business—Recent Events—4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes."

Income Taxes

On December 22, 2017, Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), was enacted by the U.S. government. The Tax Act made broad and complex changes to the U.S. corporate income tax code. Among other changes, the Tax Act: (i) reduced the U.S. federal corporate income tax rate from 35% to 21%; (ii) repealed the corporate alternative minimum tax and provided for a refund of previously accrued alternative minimum tax credits; (iii) modified the provisions relating to the limitations on deductions for executive compensation of publicly traded corporations; (iv) enacted new limitations regarding the deductibility of interest expense; and (v) imposed new limitations on the utilization of NOLs arising in taxable years beginning after December 31, 2017.

Our operations, which are located in Texas, are subject to an entity-level tax, the Texas margin tax, at a statutory rate of up to 0.75% of revenues less operating expenses attributable to operations in Texas. 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 21% of pretax earnings and, as such, the amount of our future U.S. federal income tax will be dependent upon our future taxable income.

Capital Expenditures

Our drilling, completions and infrastructure activities are capital intensive and require us to make substantial capital expenditures, which vary from year to year. For further information about our capital expenditures, see "Item 1. Business—Overview" and "—Capital Requirements and Sources of Liquidity."

The amount and timing of our future capital expenditures are 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 working interest owners.

Impact of ASC Topic 606 Adoption

We adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. As a result of the control model analysis discussed in *Note 3—Revenue from Contracts with Customers*, we modified our accounting and presentation of natural gas and NGLs sales and associated volumes, and transportation and processing costs, under certain marketing agreements. Revenues related to certain of our agreements are presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are presented as Transportation and processing costs on our consolidated statements of operations. Additionally, all references to production and per Boe unit costs reflect this adoption, which has the effect of increasing certain natural gas and NGLs volumes and revenues, offset by a corresponding transportation and processing expense, such that there is no change to reported net income.

Results of Operations

Production Revenues

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

	Year Ended December 31,	
	2019	2018
Production revenues (in thousands):		
Oil sales	$ 1,757,315	$ 1,536,244
Natural gas sales	36,774	51,231
Natural gas liquids sales	155,888	227,272
Total production revenues	$ 1,949,977	$ 1,814,747
Average realized prices[(1)]:		
Oil, without realized derivatives (per Bbl)	$ 55.50	$ 60.59
Oil, with realized derivatives (per Bbl)	53.62	58.07
Natural gas, without realized derivatives (per Mcf)	0.71	1.37
Natural gas, with realized derivatives (per Mcf)	0.78	1.38
Natural gas liquids (per Bbl)	14.17	27.21
Average price per Boe, without realized derivatives	37.99	45.44
Average price per Boe, with realized derivatives	36.91	43.85
Production:		
Oil (MBbls)	31,664	25,356
Natural gas (MMcf)	51,933	37,365
Natural gas liquids (MBbls)	11,002	8,353
Total (MBoe)	51,322	39,937
Average daily production volume:		
Oil (Bbls)	86,751	69,468
Natural gas (Mcf)	142,282	102,370
Natural gas liquids (Bbls)	30,142	22,885
Total (Boe)	140,608	109,416

(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.

The table below shows, for the periods indicated, our average realized oil price as a percentage of the average NYMEX oil price, our average realized natural gas price as a percentage of the average NYMEX gas price, and our average realized NGLs price as a percentage of the average NYMEX oil price. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil, natural gas and NGLs revenues. Realized oil, natural gas and NGLs prices are the actual prices realized at the wellhead adjusted for quality, transportation fees and costs, differentials, marketing premiums or deductions and other factors that affect the price received at the wellhead. During the year ended December 31, 2019, most of our oil production was sold at NYMEX WTI and most of our natural gas production was sold at Waha Hub prices.

	Year Ended December 31,	
	2019	2018
Average realized oil price ($/Bbl)	$ 55.50	$ 60.59
Average NYMEX ($/Bbl)	57.01	64.80
Differential to NYMEX	(1.51)	(4.21)
Average realized oil price as a percentage of average NYMEX oil price	97%	94%
Average realized natural gas price ($/Mcf)	$ 0.71	$ 1.37
Average NYMEX ($/Mcf)	2.53	3.07
Differential to NYMEX	(1.82)	(1.70)
Average realized natural gas price as a percentage of average NYMEX gas price	28%	45%
Average realized NGLs price ($/Bbl)	$ 14.17	$ 27.21
Average NYMEX ($/Bbl)	57.01	64.80
Differential to NYMEX	(42.84)	(37.59)
Average realized NGLs price as a percentage of average NYMEX oil price	25%	42%

As reflected in the table above, our price differential for oil was significantly larger during the year ended December 31, 2018 than during the year ended December 31, 2019. Widened oil and natural gas basis differentials were largely attributable to industry concerns regarding the sufficiency of pipeline takeaway capacity for oil, natural gas and NGLs production. As of December 31, 2019, we had not experienced material pipeline-related interruptions to our oil, natural gas or NGLs production.

Oil, natural gas and NGLs revenues. Our oil, natural gas and NGLs revenues totaled $1,950.0 million and $1,814.7 million during the years ended December 31, 2019 and 2018, respectively.

Our oil, natural gas and NGLs revenues increased by $135.3 million, or 7%, to $1,950.0 million for the year ended December 31, 2019 from $1,814.7 million for the year ended December 31, 2018.

As shown in the following tables, from the year ended December 31, 2018 to the year ended December 31, 2019, the net dollar effect of the decrease in oil, natural gas and NGLs prices was $339.0 million and the net dollar effect of the increase in production volumes of oil, natural gas and NGLs was $474.2 million.

	Change in prices(1)	2019 Production volumes(2)	Total net dollar effect of change
Effect of change in price:			(in thousands)
Oil	$ (5.09)	31,664	$ (161,112)
Natural gas	(0.66)	51,933	(34,430)
Natural gas liquids	(13.04)	11,002	(143,459)
Total production revenues due to change in price			$ (339,001)

	Change in production volumes(2)	2018 Average prices(1)	Total net dollar effect of change
Effect of change in production volumes:			(in thousands)
Oil	6,308	$ 60.59	$ 382,183
Natural gas	14,568	1.37	19,973
Natural gas liquids	2,649	27.21	72,075
Total production revenues due to change in production volumes			$ 474,231

(1) Oil and NGLs prices are shown per Bbl and natural gas prices are shown per Mcf.

(2) Oil and NGLs production volumes are shown in MBbls and natural gas production volumes are shown in MMcf.

Other Revenues

Other revenues totaled $8.8 million and $11.7 million during the years ended December 31, 2019 and 2018, respectively. Other revenues decreased by $2.9 million, or 24%, to $8.8 million from $11.7 million for the year ended December 31, 2019. The decrease is predominantly associated with decreased income from right-of-way and easement fees charged by Parsley Minerals, LLC to third parties and the loss of drilling service fees charged by Pacesetter to third parties, which ceased operations in 2018.

Operating expenses

The following table summarizes our operating expenses for the periods indicated:

	Year ended December 31,	
	2019	2018
Operating expenses (in thousands):		
Lease operating expenses	$ 177,148	$ 144,292
Transportation and processing costs	41,198	32,573
Production and ad valorem taxes	124,961	108,342
Depreciation, depletion and amortization	794,740	584,857
General and administrative expenses[(1)]	152,700	150,955
Exploration and abandonment costs	100,211	162,539
Acquisition costs	7,616	167
Accretion of asset retirement obligations	1,465	1,422
Rig termination costs	13,250	—
Gain on sale of property	(2,095)	(6,454)
Restructuring and other termination costs	1,562	—
Other operating expenses	8,788	19,863
Total operating expenses	$ 1,421,544	$ 1,198,556
Operating expenses per Boe:		
Lease operating expenses	$ 3.45	$ 3.61
Transportation and processing costs	0.80	0.82
Production and ad valorem taxes	2.43	2.71
Depreciation, depletion and amortization	15.49	14.64
General and administrative expenses	2.98	3.78
Exploration and abandonment costs	1.95	4.07
Acquisition costs	0.15	—
Accretion of asset retirement obligations	0.03	0.04
Rig termination costs	0.26	—
Gain on sale of property	(0.04)	(0.16)
Restructuring and other termination costs	0.03	—
Other operating expenses	0.17	0.50
Total operating expenses per Boe	$ 27.70	$ 30.01

(1) General and administrative expenses include stock-based compensation expense of $20.7 million and $19.9 million for the years ended December 31, 2019 and 2018, respectively.

Lease operating expenses. Lease operating expenses increased 23% to $177.1 million during the year ended December 31, 2019 from $144.3 million during the year ended December 31, 2018. The increase is primarily due to the increase in our asset base, including both operated and non-operated wells. On a per Boe basis, lease operating expenses decreased $0.16 per Boe, or 4%, to $3.45 per Boe for the year ended December 31, 2019 from $3.61 per Boe for the year ended December 31, 2018. The decrease in lease operating expense per Boe is primarily attributable to a 29% increase in production during the same period.

Transportation and processing costs. Transportation and processing costs increased 26% to $41.2 million during the year ended December 31, 2019 from $32.6 million during the year ended December 31, 2018. Transportation and processing costs represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. The increase in transportation and processing costs is directly related to the increase in our natural gas and NGLs volumes. Refer to Note 3—Revenue from Contracts with Customers in our consolidated financial statements for additional discussion.

Production and ad valorem taxes. Production and ad valorem taxes increased 15% to $125.0 million during the year ended December 31, 2019 from $108.3 million during the year ended December 31, 2018. On a per Boe basis, production and ad valorem taxes decreased 10% to $2.43 per Boe for the year ended December 31, 2019 from $2.71 per Boe for the year ended December 31, 2018. Overall, production taxes increased by approximately $2.6 million, reflecting increased production volumes, and ad valorem taxes increased $14.1 million, reflecting increased property assessments.

Depreciation, depletion and amortization. DD&A expense increased 36% to $794.7 million for the year ended December 31, 2019 from $584.9 million for the year ended December 31, 2018. On a per Boe basis, DD&A increased 6% to $15.49 for the year ended December 31, 2019 from $14.64 per Boe for the year ended December 31, 2018. These increases are largely attributable to acquisitions and development activity that resulted in a $2,140.4 million increase in costs subject to depletion and a 29% increase in production during the year ended December 31, 2019. These increases were partially offset by a 14% increase in total proved reserves as of December 31, 2019, as compared to December 31, 2018.

General and administrative expenses. General and administrative expenses increased 1% to $152.7 million during the year ended December 31, 2019 from $151.0 million during the year ended December 31, 2018, primarily due to ongoing corporate cost savings initiatives. On a per Boe basis, general and administrative expenses decreased 21% to $2.98 per Boe for the year ended December 31, 2019 from $3.78 per Boe for the year ended December 31, 2018, which relates to the 29% increase in total production volume during the period as well as the 1% decrease in absolute costs.

Exploration and abandonment costs. The following table provides a breakdown of exploration and abandonment costs incurred during the periods indicated (in thousands):

	Year Ended December 31,	
	2019	2018
Leasehold abandonments and impairments	$ 99,225	$ 160,834
Geological and geophysical costs	978	1,479
Other	8	226
Total exploration and abandonment costs	$ 100,211	$ 162,539

During the years ended December 31, 2019 and 2018, we recognized total leasehold abandonment and impairment charges of approximately $99.2 million and $160.8 million, respectively, which primarily relate to expired acreage or expiring acreage that is probable of reverting to the lessor. Consistent with our commitment to capital discipline and in response to recent commodity price trends, we intend to reduce our 2020 leasing and acquisition spending. As a result, in the fourth quarter of 2019, we recorded non-cash leasehold impairment expense of $62.8 million relating to acreage expiring in future periods because we have no current plans to drill or extend the applicable leases prior to their expiration. For the years ended December 31, 2019 and 2018 we recognized non-cash leasehold abandonment expense of $36.4 million and $33.8 million due to leases expiring during those periods for which previous efforts to sell or trade these leases were unsuccessful. In determining the amount of non-cash abandonment charges for such periods, we considered the application of the factors described under "—Critical Accounting Policies and Estimates—Oil and Natural Gas Properties."

During the years ended December 31, 2019 and 2018, we incurred geological and geophysical expenses of approximately $1.0 million and $1.5 million, respectively. Our geological and geophysical expenses consist of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to increased geoscientific analysis of our acreage.

We recognized other exploration costs during the years ended December 31, 2019 and 2018 of $8.0 thousand and $0.2 million, respectively, which include research and other similar costs.

Acquisition Costs. During the years ended December 31, 2019 and 2018, we incurred $7.6 million and $0.2 million, respectively, of acquisition costs, which include legal and other due diligence fees associated with the acquisitions described in Note 6—Acquisitions of Oil and Natural Gas Properties to our consolidated financial statements included elsewhere in this

Annual Report. The costs incurred during the year ended December 31, 2019 were primarily related to the completion of the Jagged Peak Acquisition.

Rig termination costs. During the year ended December 31, 2019, we incurred $13.3 million of rig termination costs, which were incurred in connection with the early termination of drilling rig contracts. There were no such costs incurred during the year ended December 31, 2018.

(Gain) loss on sale of property. During the years ended December 31, 2019 and 2018, we incurred gains of $2.1 million and $6.5 million, respectively, as a result of the sale of property as discussed in *Note 7—Sales of Property, Plant and Equipment* to our consolidated financial statements included elsewhere in this Annual Report.

Other operating expenses. During the years ended December 31, 2019 and 2018, other operating expenses primarily included costs associated with idle charges, impairment of certain other property, plant and equipment and bad debt expense, as well as costs incurred by our majority-owned subsidiary, Pacesetter. We incurred idle charges of $5.7 million and $8.8 million, respectively for the years ended December 31, 2019 and 2018. The nonrecurring idle charges are a result of temporarily idled contracted assets and services. In addition, during the fourth quarter of 2019, we recorded an impairment expense of $2.6 million associated with leasehold improvements for office space in Austin, Texas that we are no longer using as discussed in *Note 16—Disclosures About Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report. During the year ended December 31, 2018 we recorded bad debt expense of $2.8 million as discussed in *Note 2—Summary of Significant Accounting Policies* to our consolidated financial statements included elsewhere in this Annual Report, and we did not incur any such costs during the year ended December 31, 2019. Costs incurred during the normal course of business of our majority-owned subsidiary, Pacesetter, were $6.9 million during the year ended December 31, 2018, and we did not incur any such costs during the year ended December 31, 2019. As discussed in *Note 7—Sales of Property, Plant and Equipment* to our consolidated financial statements included elsewhere in this Annual Report, during the year ended December 31, 2018, Pacesetter completed the sale of all of its physical assets.

Other income (expenses)

The following table summarizes our other income and expenses for the periods indicated (in thousands):

	Year ended December 31,	
	2019	2018
Other income (expenses):		
Interest expense, net	$ (133,640)	$ (131,460)
(Loss) gain on derivatives	(131,212)	50,342
Change in TRA liability	—	(437)
Interest income	801	5,464
Other expenses	(1,364)	(340)
Total other expenses, net	$ (265,415)	$ (76,431)

Interest expense. Interest expense increased 2% to $133.6 million in the year ended December 31, 2019 from $131.5 million during the year ended December 31, 2018.

(Loss) gain on derivatives. Loss on derivatives increased $181.5 million to a loss of $131.2 million during the year ended December 31, 2019 as compared to a gain of $50.3 million during the year ended December 31, 2018, as higher commodity prices decreased the value of our derivative portfolio.

Change in TRA liability. We recorded a $0.4 million expense during the year ended December 31, 2018, associated with an increase in the TRA liability primarily resulting from the reversal of the valuation allowance recorded during 2017. There were no such charges recorded during the year ended December 31, 2019.

Interest income. Interest income decreased $4.7 million to $0.8 million during the year ended December 31, 2019 as compared to $5.5 million during the year ended December 31, 2018, as a result of decreased interest income offset by increased amortization, associated with our previous held to maturity securities, as discussed in *Note 16—Disclosures About Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report.

Other expenses. Other expenses increased $1.1 million to $1.4 million during the year ended December 31, 2019 as compared to $0.3 million during the year ended December 31, 2018.

Income Tax Expense

For the years ended December 31, 2019 and 2018, our operations were taxed at a combined U.S. federal and state effective tax rate of 22.6% and 19.1%, respectively. During the year ended December 31, 2019, we recognized an income tax expense of $61.4 million, a decrease of $44.1 million, as compared to the income tax expense of $105.5 million we recognized during the year ended December 31, 2018. These changes were attributable to the changes in our results of operations, discussed above, as well as the impact of net income attributable to noncontrolling ownership interests, the impact of state income taxes and the increase to valuation allowance that was recorded in 2019 described in Note 12—Income Taxes to our consolidated financial statements included elsewhere in this Annual Report.

Capital Requirements and Sources of Liquidity

The following table sets forth our capital expenditures for drilling, completions and infrastructure for the periods indicated (in thousands):

	Year Ended December 31,	
	2019	2018
Capital expenditures	$ 1,372,919	$ 1,762,218

Our 2020 budget for capital development expenditures is approximately $1,600.0 million to $1,800.0 million, approximately 85% of which is expected to be used for drilling and completions and approximately 15% of which is expected to be used for infrastructure and other expenditures. We expect approximately 25% to 30% of this budget to be associated with drilling and completions for proved undeveloped reserves as of December 31, 2019. Our capital budget excludes any amounts that may be paid for acquisitions. For the years ended December 31, 2019 and 2018, our aggregate drilling and completion expenditures were $1,157.1 million and $1,510.1 million, respectively, and our infrastructure and other expenditures were $215.8 million and $252.1 million, respectively, for totals of $1,372.9 million and $1,762.2 million, respectively. Of these totals, $457.2 million and $308.1 million were associated with drilling, completion and facility buildout for proved undeveloped reserves as of December 31, 2018 and 2017, respectively. The amount and timing of our 2020 capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned 2020 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Based upon current oil and natural gas price expectations for fiscal year 2020, we believe that our cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement will be sufficient to fund our operations through 2020. As of December 31, 2019, our liquidity is as follows (in millions):

Cash and cash equivalents	$ 20.7
Revolving Credit Agreement Availability	993.3
Liquidity	$ 1,014.0

Pro forma for the closing of the Jagged Peak Acquisition, the 2028 Notes Offering and the 2024 Notes Redemption, our liquidity as of December 31, 2019 was approximately $674.7 million.

Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures required to more fully develop our properties. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled in drilling locations not associated with proved reserves on our December 31, 2019 reserve report. The failure to achieve anticipated production and cash flows from operations from such wells could result in a reduction in future capital spending. Further, our capital expenditure budget for the year ended December 31, 2020 does not allocate any amounts for acquisitions of oil and natural gas properties. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt or equity securities or other means. We cannot assure you that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Dividends

During the third quarter of 2019, our board of directors initiated our first quarterly dividend, payable on issued and outstanding shares of Class A common stock, and, in its capacity as the managing member of Parsley LLC, a corresponding distribution from Parsley LLC to the PE Unitholders. The portion of the Parsley LLC distribution attributable to PE Units held by Parsley Energy, Inc. was used to fund the quarterly dividend on issued and outstanding shares of Class A common stock.

The following table sets forth information with respect to cash dividends and distributions declared by our board of directors during 2019:

Declaration Date(1)	Record Date	Payment Date	Dividend/Distribution Amount(2)	Total Dividend/ Distribution Payment(3) (in thousands)
August 6, 2019	September 20, 2019	September 30, 2019	$ 0.03	$ 9,547
November 5, 2019	December 10, 2019	December 20, 2019	$ 0.03	$ 9,548

(1) On January 23, 2020, our board of directors declared a cash dividend of $0.05 per share of Class A common stock and, in its capacity as the managing member of Parsley LLC, a corresponding distribution of $0.05 per PE Unit, payable on March 20, 2020 to holders of Class A common stock and PE Unitholders of record as of March 10, 2020. The portion of the Parsley LLC distribution attributable to PE Units held by Parsley Energy, Inc. will be used to fund the quarterly dividend on issued and outstanding shares of Class A common stock.

(2) Per share of Class A common stock and per PE Unit. The portion of the Parsley LLC distribution attributable to PE Units held by Parsley Energy, Inc. was used to fund the quarterly dividend on issued and outstanding shares of Class A common stock.

(3) Reflects total cash dividend and distribution payments made, or to be made, to holders of Class A common stock and PE Unitholders (other than Parsley Energy, Inc.) as of the applicable record date.

We did not pay dividends on our Class A common stock or distributions on our PE Units during the year ended December 31, 2018.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our results of operations, financial condition, liquidity, capital requirements, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. In addition, our debt agreements and the Parsley LLC Agreement place certain restrictions on Parsley LLC's ability to distribute cash to PE Unitholders (including to us to fund dividends to holders of Class A common stock).

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Year Ended December 31, 2019	Year Ended December 31, 2018
Net cash provided by operating activities	$ 1,286,279	$ 1,218,974
Net cash used in investing activities	(1,400,799)	(1,594,036)
Net cash used in financing activities	(27,957)	(15,911)

Cash flows provided by operating activities. Net cash provided by operating activities was approximately $1,286.3 million and $1,219.0 million during the years ended December 31, 2019 and 2018, respectively.

Net cash provided by operating activities increased $67.3 million due to a $132.4 million increase in total revenues, offset by, among other items, a decrease of $14.9 million in cash based derivative payments and an increase of $60.2 million in cash based operating expenses. Cash based operating expenses include lease operating expenses, transportation and processing costs, production and ad valorem taxes, cash general and administrative expenses, rig termination, restructuring and other termination costs, acquisition costs and certain other operating expenses.

Cash flows used in investing activities. Net cash used in investing activities was approximately $1.4 billion and $1.6 billion during the years ended December 31, 2019 and 2018, respectively.

The $193.2 million reduction in the amount of cash used in investing activities during the year ended December 31, 2019 as compared to the year ended December 31, 2018 was due primarily to a $414.6 million decrease in development costs related to our oil and natural gas properties and a $85.0 million decrease in acquisition costs, offset by a decrease of $192.3 million in proceeds received from the sale of property and a $149.3 million decrease in cash received from short-term investment maturities during the year ended December 31, 2019.

Cash flows used in financing activities. Net cash used in financing activities was approximately $28.0 million and $15.9 million during the years ended December 31, 2019 and 2018, respectively.

Net cash used in financing activities increased by $12.1 million during the year ended December 31, 2019 as compared to the year ended December 31, 2018 primarily as a result of dividend payments of $18.9 million offset by a decrease of $5.3 million related to the vesting of time-based restricted stock and time-based restricted stock units. In addition, Pacesetter paid an owner distribution of $0.6 million, as discussed in *Note 10—Equity—Noncontrolling Interests* to our consolidated financial statements included elsewhere in this Annual Report.

Capital Sources

Revolving Credit Agreement. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for a description of the Revolving Credit Agreement.

6.250% Senior Unsecured Notes due 2024. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 2024 Notes. We intend to use the net proceeds of the 2028 Notes and borrowings under the Revolving Credit Agreement to redeem all of the 2024 Notes on March 7, 2020 at a redemption price of 104.688%, plus accrued and unpaid interest to the redemption date, pursuant to the terms of the indenture relating to the 2024 Notes.

5.375% Senior Unsecured Notes due 2025. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding our 5.375% senior unsecured notes due 2025 (the “2025 Notes”).

5.250% Senior Unsecured Notes due 2025. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the New 2025 Notes.

5.875% Senior Unsecured Notes due 2026. See *Note 17—Subsequent Events—Jagged Peak Acquisition* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the Jagged Peak 2026 Notes.

5.625% Senior Unsecured Notes due 2027. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 5.625% senior unsecured notes due 2027 (the “2027 Notes”).

4.125% Senior Unsecured Notes due 2028. See “Item 1. Business—Recent Events—4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes” and *Note 17—Subsequent Events—4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 2028 Notes.

Derivative Activity. We plan to continue our practice of entering into hedging arrangements to (i) reduce the impact of commodity price volatility on our cash flow from operations and (ii) support our annual capital budgeting and expenditure plans. Under this strategy, we intend to continue our historical practice of entering into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil and natural gas production.

Working Capital. Our working capital totaled ($397.3) million and ($108.2) million at December 31, 2019 and 2018, respectively. Our collection of receivables has historically been timely and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents and short-term investments totaled $20.7 million and $163.2 million at December 31, 2019 and 2018, respectively. The $142.5 million decrease in cash and cash equivalents and short-term investments is attributable to the development of our oil and natural gas properties as well as the $52.0 million in acquisitions described in *Note 6—Acquisitions of Oil and Natural Gas Properties* to our consolidated financial statements included elsewhere in this Annual Report. Due to the amounts that we accrue related to our drilling program, we may incur working capital deficits in the future. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, derivative liabilities and other obligations.

We had the following contractual obligations at December 31, 2019 (in thousands):

	Payments Due by Period For the Year Ended December 31,						
	2020	2021	2022	2023	2024	Thereafter	Total
Revolving Credit Agreement[1]	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Notes[2]	—	—	—	—	400,000	1,800,000	2,200,000
Interest[3]	122,421	122,421	122,421	122,421	108,139	126,143	723,966
Finance lease obligations[4]	2,234	1,176	184	13	—	—	3,607
Operating lease obligations[5]	17,713	22,165	24,900	23,043	22,361	135,076	245,258
Drilling commitments[6]	48,864	21,911	5,235	—	—	—	76,010
Asset retirement obligations[7]	2,900	925	885	846	809	17,074	23,439
Transportation and crude oil sales agreements[8]	41,534	79,530	79,770	75,112	70,962	126,666	473,574
Derivative obligations[9]	58,855	—	—	—	—	—	58,855
Total	$ 294,521	$ 248,128	$ 233,395	$ 221,435	$ 602,271	$2,204,959	$3,804,709

(1) Does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees related to the Revolving Credit Agreement because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) Includes principal only.

(3) Includes fixed rate interest on the 2024 Notes, the 2025 Notes, the New 2025 Notes and the 2027 Notes.

(4) We periodically enter into finance lease agreements payable in connection with the lease of vehicles for operations and field personnel.

(5) We lease equipment and office facilities under non-cancellable operating leases.

(6) We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital is incurred or rig services are provided.

(7) Amounts represent estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

(8) Amounts equal the total deficiency fees payable, based on assumptions management considers reasonable, if we are unable to meet all of our contractual delivery commitments under our long-term transportation and crude oil sales agreements. Of the total $473.6 million, $204.1 million is associated with delivery commitments subject to the commencement of operations of third-party terminal and pipeline systems. In the event we are unable to meet any portion of such contractual delivery commitments, we may purchase commodities in the market at then-current market prices to satisfy the portion of such commitment that was not delivered, in which case such deficiency fees would not be payable. For additional information regarding our transportation and crude oil sales agreements, see "Item 1. Business—Oil and Natural Gas Production and Operations—Transportation and Delivery Commitments" and *Note 14—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report.

(9) We enter into derivative agreements to hedge future production. We have deferred payment of the premium for certain agreements until the period of settlement.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our consolidated financial statements. See below for an expanded discussion of our significant accounting policies and estimates made by management.

Oil and Natural Gas Properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized.

Exploration and abandonment 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, impairment and amortization 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 a 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.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties and mineral interests are depleted. Depletion of capitalized costs is calculated using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. Capitalized development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale of a complete or partial unit of a proved property, we determine the impact to the unit-of-production amortization rate. If the impact to the unit-of-production amortization rate is considered significant, the cost and related accumulated DD&A are removed from the property accounts and any gain or loss is recognized. If the impact to the unit-of-production amortization rate is not considered significant, the sale is accounted for as a normal retirement with no gain or loss recognized.

We review our long-lived assets to be held and used, including proved oil and natural gas properties by field. Whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, an impairment loss is indicated if the sum of the expected future cash flows related to proved properties in the applicable field is less than the carrying amount of the assets. In this circumstance, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. See *Note 16—Disclosures About Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for additional information for additional information regarding the impairment of proved oil and natural gas properties.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved costs are capitalized until reclassified from unproved properties to proved properties when proved reserves are discovered or are expensed as the leases expire or we specifically identify leases that are probable of reverting to the lessor.

Unproved properties are assessed periodically for impairment on a property by property basis by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales, remaining lease terms and the expiration of all or a portion of such projects. Our periodic assessment also considers our ability to enter into leasehold exchange transactions and leasehold extensions that allow for higher concentrations of ownership and development. We recognize impairment expense for unproved properties at the earlier of the time when the lease term or continuous development clause has expired or management estimates the lease will expire before it is drilled, sold or traded. The impairment of unproved oil and natural gas properties is recorded in *Exploration and abandonment costs* in our consolidated statements of operations. Based on this assessment, we expensed $62.8 million and $127.0 million of undeveloped leasehold during the years ended December 31, 2019 and 2018, respectively, related to the expected future abandonment of expiring acreage.

We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining length of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill wells on undeveloped leases or make payments to extend leases that may be close to expiration;
- our ability to exchange leasehold positions with other companies that allow for higher concentrations of ownership and development potential; and
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases.

For sales of all of our working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of less than all of our working interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

The estimates of proved oil and natural gas reserves utilized in the preparation of our consolidated financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing first day of the month 12-month average price, net of historical differentials, with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above, may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

This Annual Report presents estimates of our proved reserves as of December 31, 2019, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2019 was based on an unweighted first day of the month average 12-month U.S. Energy Information Administration WTI posted price, net of differential, of $53.97 per Bbl for oil and $15.46 per Bbl for NGLs and a Waha spot natural gas price, net of differential, of $0.71 per Mcf for natural gas.

Our internal reserve engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows, which are then audited by NSAI, our independent third-party petroleum consulting firm. Even though our internal reserve engineers, technical staff and independent reserve engineers are knowledgeable and follow authoritative guidelines for estimating and auditing reserves, they must make a number of subjective assumptions based on professional judgments in developing and auditing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this Annual Report as of December 31, 2019 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2019 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 1A. Risk Factors" and "Item 2. Properties" for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Income Taxes

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

We periodically assess whether it is more likely than not that we will generate sufficient taxable income to realize our deferred income tax assets, including NOLs. In making this determination, we consider all available evidence and make certain assumptions. We consider, among other things, our deferred tax liabilities, the overall business environment, our historical earnings and losses, current industry trends and our outlook for future years.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019 and 2018. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

As of December 31, 2019, we were party to certain transportation and sale agreements providing for the delivery of fixed and determinable quantities of oil and natural gas. If production volumes are not sufficient to meet these contracted delivery commitments, we may be subject to deficiency fees unless we purchase commodities in the market to satisfy such commitments. See *Note 14—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report.

We do not otherwise maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the notes to our consolidated financial statements.

Recent Accounting Pronouncements

For information regarding recently issued accounting pronouncements that impact us, see *Note 2—Summary of Significant Accounting Policies* to our consolidated financial statements included elsewhere in this Annual Report, which is incorporated herein by reference.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in the prices of the commodities we sell. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil and natural gas production. Pricing for our production has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

We enter into multiple types of commodity derivative contracts to (i) reduce the effect of price volatility on our oil and natural gas revenues and (ii) support our annual capital budgeting and expenditure plans. We plan to continue our practice of entering into such transactions at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil and natural gas production. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations. For a description of our open positions at December 31, 2019, see *Note 4—Derivative Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report.

We do not require collateral from our counterparties for entering into derivative instruments, so in order to mitigate the credit risk associated with such derivative instruments, we typically enter into an International Swap Dealers Association Master Agreement ("ISDA Agreement") with each of our counterparties. The ISDA Agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each derivative transaction between the counterparty and us separately, the ISDA Agreement enables the counterparty and us to aggregate all trades under such agreement and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under a single trade can trigger rights to terminate all trades with such counterparty that are subject to the ISDA Agreement; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

As of December 31, 2019, the fair market value of our oil and natural gas derivative contracts was a net liability of $30.9 million, including net deferred premium payables of $58.9 million. The deferred premium payable is a fixed amount and is not marked to fair market value. As of December 31, 2019, the fair market value of our oil derivative contracts was a net liability of $32.9 million. Based on our open oil derivative positions at December 31, 2019, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $83.5 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $78.2 million. As of December 31, 2019, the fair market value of our natural gas derivative contracts was a net asset of $2.0 million. Based on our open natural gas derivative positions at December 31, 2019, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $1.4 million, while a 10% decrease in the NYMEX Henry Hub price would increase our natural gas derivative asset by approximately $1.3 million. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs."

Counterparty Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. We plan to continue to evaluate the credit standings of our counterparties in a similar manner. The majority of our derivative contracts currently in place are with lenders under our Revolving Credit Agreement, each of whom has an investment grade rating.

Interest Rate Risk

Our market risk exposure related to changes in interest rates relates primarily to debt obligations and the amount of interest we earn on our short-term investments. As of December 31, 2019, we had $2.2 billion of fixed-rate long-term debt outstanding with a weighted average interest rate of 5.6%, and, pro forma for the Jagged Peak Acquisition, the 2028 Notes Offering and the 2024 Notes Redemption, we had $2.7 billion of fixed-rate long-term debt outstanding with a weighted average interest rate of 5.6%. Although near term changes may impact the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss. We are exposed to interest rate risk as a result of our Revolving Credit Agreement, which requires us to pay higher interest rate margins as we utilize a larger percentage of our available commitments. As of December 31, 2019, we had no borrowings outstanding under our Revolving Credit Agreement; however, pro forma for the Jagged Peak Acquisition, the 2028 Notes Offering and the 2024 Notes Redemption, we had $365.7 million of borrowings outstanding with a weighted average interest rate of 3.1%. Based on this pro forma amount outstanding, an increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $3.7 million. We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents and short-term investment balances. As of December 31, 2019, our cash and cash equivalents were $20.7 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements and supplementary data are included in this Annual Report beginning on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2019, at the reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with GAAP.

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

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, our management believes that our internal control over financial reporting was effective as of December 31, 2019.

This Annual Report includes an attestation report of KPMG LLP, our independent registered public accounting firm, on our internal control over financial reporting as of December 31, 2019, which is included in this Annual Report on page F-3.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1. The following documents are filed as part of this Annual Report or incorporated by reference:

    a. Financial Statements:

    Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

    b. Financial Statement Schedules:

    All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements and related notes.

2. Exhibits

    The exhibits required to be filed by this Item 15(b) are set forth in the Exhibit Index included below.

EXHIBIT INDEX

Exhibit No.	
2.1#	Agreement and Plan of Merger, dated as of October 14, 2019, by and among Parsley Energy, Inc., Jackal Merger Sub, Inc. and Jagged Peak Energy Inc. (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 15, 2019).
3.1	Amended and Restated Certificate of Incorporation of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
3.2	Amended and Restated Bylaws of Parsley Energy, Inc., dated October 26, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 30, 2018).
4.1	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K, File No. 333-195230, filed with the SEC on February 27, 2019).
4.2	Indenture, dated May 27, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 27, 2016).
4.3	First Supplemental Indenture, dated August 18, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 19, 2016).
4.4	Second Supplemental Indenture, dated October 27, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
4.5	Third Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.6*	Fourth Supplemental Indenture, dated January 15, 2020, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024.
4.7	Indenture, dated December 13, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.375% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 13, 2016).
4.8	First Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.375% Senior Notes due 2025 (incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.9*	Second Supplemental Indenture, dated January 15, 2020, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.375% Senior Notes due 2025.
4.10	Indenture, dated February 13, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.250% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 13, 2017).
4.11	First Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.250% Senior Notes due 2025 (incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.12*	Second Supplemental Indenture, dated January 15, 2020, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.250% Senior Notes due 2025.

Exhibit No.	
4.13	Indenture, dated October 11, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.625% Senior Notes due 2027 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 11, 2017).
4.14*	First Supplemental Indenture, dated January 15, 2020, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.625% Senior Notes due 2017.
4.15	Indenture, dated May 8, 2018, by and among Jagged Peak Energy LLC, Jagged Peak Energy Inc. and Wells Fargo Bank, National Association, as trustee, related to the 5.875% Senior Notes due 2026 (incorporated by reference to Exhibit 4.1 to Jagged Peak's Current Report Form 8-K, File No. 001-37995, filed with the SEC on May 8, 2018).
4.16	First Supplemental Indenture, dated December 17, 2019, by and among SoDe Water LLC, Jagged Peak Energy LLC, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee, related to the 5.875% Senior Notes due 2026 (incorporated by reference to Exhibit 4.13 to the Company's Registration Statement on Form S-3ASR, File No. 333-235884, filed with the SEC on January 10, 2020).
4.17	Second Supplemental Indenture, dated January 10, 2020, by and among Jackal Merger Sub A, LLC, Jagged Peak Energy LLC, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee, related to the 5.875% Senior Notes due 2026 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on January 10, 2020).
4.18*	Third Supplemental Indenture, dated January 15, 2020, by and among Jagged Peak Energy LLC, Parsley Energy, LLC, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee, related to the 5.875% Senior Notes due 2026.
4.19*	Fourth Supplemental Indenture, dated January 15, 2020, by and among Jagged Peak Energy LLC, Parsley Energy, LLC, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee, related to the 5.875% Senior Notes due 2026.
4.20	Indenture, dated February 11, 2020, among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 4.125% Senior Notes due 2028 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 11, 2019).
4.21	Registration Rights and Lock-Up Agreement, dated as of April 20, 2017, by and between Parsley Energy, Inc. and the Holders party thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.22	Second Amended and Restated Registration Rights Agreement, dated as of April 20, 2017, by and among Parsley Energy, LLC, Parsley Energy, Inc. and each of the parties listed as Owners on the signature pages thereto (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.23	Registration Rights Agreement, dated as of October 14, 2019, by and among Parsley Energy, Inc., Q-Jagged Peak Energy Investment Partners, LLC and any subsequent holder from time to time party thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 15, 2019).
4.24*	Description of Parsley's Energy, Inc.'s Class A Common Stock.
10.1	Credit Agreement, dated October 28, 2016, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on November 2, 2016).
10.2	First Amendment to Credit Agreement, dated as of February 13, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).

Exhibit No.	
10.3	Second Amendment to Credit Agreement, dated as of April 11, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).
10.4	Third Amendment to Credit Agreement, dated as of April 28, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).
10.5	Fourth Amendment to Credit Agreement, dated as of May 22, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 4, 2017).
10.6	Fifth Amendment to Credit Agreement, dated as of October 11, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 11, 2017).
10.7	Sixth Amendment to Credit Agreement, dated as of April 30, 2018, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 3, 2018).
10.8	Seventh Amendment to Credit Agreement, dated April 23, 2019, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 24, 2019).
10.9	Eighth Amendment to Credit Agreement, dated as of January 10, 2020, among Parsley Energy, LLC as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A. as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on January 10, 2020).
10.10†	Employment Agreement, dated as of January 23, 2014, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.11†	First Amendment to Employment, Confidentiality and Non-Competition Agreement, dated as of September 30, 2016, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.12†	Letter Agreement, dated as of February 15, 2019, by and between Parsley Energy, Inc. and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 15, 2019).
10.13†	Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Matt Gallagher (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.14†	First Amendment to Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated as of February 15, 2019, by and between Parsley Energy Operations, LLC and Matt Gallagher (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 15, 2019).

Exhibit No.	
10.15†	Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Ryan Dalton (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.16†	Employment, Confidentiality and Non-Competition Agreement, dated September 26, 2018, by and between Parsley Energy Operations, LLC and David Dell'Osso (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on September 26, 2018)
10.17†	Second Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.18	Employment, Confidentiality and Non-Competition Agreement, dated as of February 26, 2014, by and between Parsley Energy Operations, LLC and Michael Hinson (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.19	First Amendment to Employment, Confidentiality and Non-Competition Agreement, dated as of September 30, 2016, by and between Parsley Energy Operations, LLC and Michael Hinson (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.20	Fourth Amended and Restated Limited Liability Company Agreement of Parsley Energy, LLC, dated July 22, 2019 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on July 25, 2019).
10.21	Tax Receivable Agreement, dated as of May 29, 2014, by and among Parsley Energy, Inc., certain members of Parsley Energy, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.22*†	Form of Indemnification Agreement for Directors and Officers.
10.23†	Form of Director Agreement (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 8, 2018).
10.24†	Director Agreement, dated as of January 10, 2020, by and between Parsley Energy, Inc. and James J. Kleckner (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on January 10, 2020).
10.25†	Director Agreement, dated as of January 10, 2020, by and between Parsley Energy, Inc. and S. Wil VanLoh, Jr. (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on January 10, 2020).
10.26†	Amended and Restated Parsley Energy, Inc. 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.27†	First Amendment to the Amended and Restated Parsley Energy, Inc. 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on January 10, 2020).
10.28†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.29†	First Amendment to Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.30†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.31†	Form of Notice of Grant of Restricted Stock (Time-Based) (incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.32†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).

Exhibit No.	
10.33†	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.34†	Form of Notice of Grant of Restricted Stock Units (Time-Based) (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.35†	Form of Notice of Grant of Restricted Stock Units (Performance-Based) (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.36†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.58 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.37†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.59 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.38†	Parsley Energy, Inc. Nonqualified Deferred Compensation Plan, effective as of December 21, 2018 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.39†	Jagged Peak Energy Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Jagged Peak's Current Report on Form 8-K (File No. 001-37995), filed with the SEC on January 31, 2017).
10.40†	Form of Employee Notice of Grant of Restricted Stock Units (incorporated by reference to Exhibit 10.3 to Jagged Peak's Current Report on Form 8-K (File No. 001-37995), filed with the SEC on April 20, 2017).
10.41†	Form of Employee Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.4 to Jagged Peak's Current Report on Form 8-K (File No. 001-37995), filed with the SEC on April 20, 2017).
21.1*	List of Subsidiaries of Parsley Energy, Inc.
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. Audit Letter as of December 31, 2019.
99.2	Netherland, Sewell & Associates, Inc. Audit Letter as of December 31, 2018 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 27, 2019).
99.3	Netherland, Sewell & Associates, Inc. Audit Letter as of December 31, 2017 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
101*	The following materials from Parsley Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2019 formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets; (ii) Consolidated Statements of Operations; (iii) Consolidated Statements of Changes in Equity; (iv) Consolidated Statements of Cash Flows; and (v) Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

† Management contract or compensatory plan or agreement

* Filed herewith.

** Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this Annual Report on Form 10-K and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

Schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant will furnish a supplemental copy of any omitted schedule or similar attachment to the Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

February 21, 2020	By:	/s/ Matt Gallagher
		Matt Gallagher
		President and Chief Executive Officer

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

February 21, 2020	By:	/s/ Matt Gallagher
		Matt Gallagher
		President, Chief Executive Officer and Director (Principal Executive Officer)
February 21, 2020	By:	/s/ Ryan Dalton
		Ryan Dalton
		Executive Vice President—Chief Financial Officer (Principal Accounting and Financial Officer)
February 21, 2020	By:	/s/ A.R. Alameddine
		A.R. Alameddine
		Director
February 21, 2020	By:	/s/ Ronald Brokmeyer
		Ronald Brokmeyer
		Director
February 21, 2020	By:	/s/ William Browning
		William Browning
		Director
February 21, 2020	By:	/s/ Hemang Desai
		Hemang Desai
		Director
February 21, 2020	By:	/s/ Karen Hughes
		Karen Hughes
		Director
February 21, 2020	By:	/s/ James J. Kleckner
		James J. Kleckner
		Director
February 21, 2020	By:	/s/ Bryan Sheffield
		Bryan Sheffield
		Executive Chairman and Chairman of the Board
February 21, 2020	By:	/s/ David H. Smith
		David H. Smith
		Director
February 21, 2020	By:	/s/ S. Wil VanLoh, Jr.
		S. Wil VanLoh, Jr.
		Director
February 21, 2020	By:	/s/ Jerry Windlinger
		Jerry Windlinger
		Director

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Parsley Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Parsley Energy, Inc. and subsidiaries (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 21, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of ASU No. 2016-02, *Leases (Topic 842)*, and has changed its method of accounting for revenue recognition as of January 1, 2018 due to the adoption of ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*.

Basis for Opinion

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

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

Critical Audit Matter

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

Assessment of the impact of estimated oil and natural gas reserves on depletion expense related to proved oil and natural gas properties

As discussed in Note 5 to the consolidated financial statements, the Company amortizes capitalized costs of proved oil and natural gas properties using the unit-of-production method based on proved oil and natural gas reserves related to the associated proved property. For the year ended December 31, 2019, the Company recorded depletion expense of proved oil and natural gas properties of $775.8 million. The Company's internal reserve engineers prepare an estimate of the proved oil and natural gas reserves, who take into consideration production, development and operating costs, and oil and natural gas prices including market differentials. The Company also engages independent reserve engineers to evaluate the proved oil and natural gas reserves estimated by the Company.

We identified the assessment of the impact of estimated oil and natural gas reserves on depletion expense related to proved oil and natural gas reserves as a critical audit matter. There was a high degree of subjectivity in evaluating the estimate of proved oil and natural gas reserves, which was a significant input into the calculation of depletion. Auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production, development and operating costs, and forecasted oil and natural gas prices inclusive of market differentials.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's depletion process, including controls related to the assumptions used to estimate proved oil and natural gas reserves. We assessed the competence, capabilities, and objectivity of the Company's internal reserve engineers and the independent reserve engineers engaged by the Company. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We compared the pricing assumptions used in the internal reserve engineers' estimate of the proved reserves to publicly available oil and natural gas pricing data. We evaluated assumptions used in the internal reserve engineers' estimate regarding future operating and development costs, and price differentials based on historical information. We compared the forecasted production assumption used by the Company in the current period to historical production and investigated differences. We compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast. We read the findings of the independent reserve engineers engaged by the Company in connection with our evaluation of the Company's reserve estimates. We analyzed and recalculated the depletion expense for compliance with industry and regulatory standards.

(signed) KPMG LLP

We have served as the Company's auditor since 2013.

Dallas, Texas
February 21, 2020

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Parsley Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Parsley Energy, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 21, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

(signed) KPMG LLP

Dallas, Texas
February 21, 2020

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(In thousands, except share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20,739	$ 163,216
Accounts receivable, net of allowance for doubtful accounts:		
Joint interest owners and other	48,785	39,564
Oil, natural gas and NGLs	192,216	136,209
Related parties	183	94
Short-term derivative instruments	127,632	191,297
Other current assets	8,818	10,332
Total current assets	398,373	540,712
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	11,272,124	9,948,246
Accumulated depreciation, depletion, amortization and impairment	(2,117,963)	(1,295,098)
Total oil and natural gas properties, net	9,154,161	8,653,148
Other property, plant and equipment net	170,306	170,739
Total property, plant and equipment, net	9,324,467	8,823,887
NONCURRENT ASSETS		
Operating lease assets, net of accumulated depreciation	128,529	—
Long-term derivative instruments	—	20,124
Other noncurrent assets	4,845	6,640
Total noncurrent assets	133,374	26,764
TOTAL ASSETS	$ 9,856,214	$ 9,391,363
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 416,346	$ 364,803
Revenue and severance taxes payable	154,556	127,265
Short-term derivative instruments	158,522	152,330
Current operating lease liabilities	61,198	—
Other current liabilities	5,002	4,547
Total current liabilities	795,624	648,945
NONCURRENT LIABILITIES		
Long-term debt	2,182,832	2,181,667
Operating lease liabilities	69,195	—
Asset retirement obligations	20,538	24,750
Deferred tax liability, net	193,409	131,523
Payable pursuant to tax receivable agreement	70,529	68,110
Financing lease liabilities	1,320	—
Long-term derivative instruments	—	16,633
Other noncurrent liabilities	119	—
Total noncurrent liabilities	2,537,942	2,422,683
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common stock		
Class A, $0.01 par value, 600,000,000 shares authorized, 282,260,133 shares issued and 281,241,443 shares outstanding at December 31, 2019 and 280,827,038 shares issued and 280,205,293 shares outstanding at December 31, 2018	2,822	2,808
Class B, $0.01 par value, 125,000,000 shares authorized, 35,420,258 and 36,547,731 issued and outstanding at December 31, 2019 and December 31, 2018	355	366
Additional paid in capital	5,200,795	5,163,987
Retained earnings	570,889	412,646
Treasury stock, at cost, 1,018,690 shares and 621,745 at December 31, 2019 and December 31, 2018	(17,428)	(11,749)
Total stockholders' equity	5,757,433	5,568,058
Noncontrolling interest	765,215	751,677
Total equity	6,522,648	6,319,735
TOTAL LIABILITIES AND EQUITY	$ 9,856,214	$ 9,391,363

The accompanying notes are an integral part of these consolidated financial statements.

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2019	2018	2017
	(In thousands, except per share data)		
REVENUES			
Oil sales	$ 1,757,315	$ 1,536,244	$ 802,230
Natural gas sales	36,774	51,231	56,571
Natural gas liquids sales	155,888	227,272	103,193
Other	8,837	11,684	5,050
Total revenues	1,958,814	1,826,431	967,044
OPERATING EXPENSES			
Lease operating expenses	177,148	144,292	102,169
Transportation and processing costs	41,198	32,573	—
Production and ad valorem taxes	124,961	108,342	59,641
Depreciation, depletion and amortization	794,740	584,857	352,247
General and administrative expenses (including stock-based compensation of $20,682, $19,877 and $19,619 for the years ended December 31, 2019, 2018 and 2017)	152,700	150,955	124,255
Exploration and abandonment costs	100,211	162,539	39,345
Acquisition costs	7,616	167	10,977
Accretion of asset retirement obligations	1,465	1,422	971
Rig termination costs	13,250	—	—
(Gain) loss on sale of property	(2,095)	(6,454)	14,332
Restructuring and other termination costs	1,562	—	—
Other operating expenses	8,788	19,863	10,638
Total operating expenses	1,421,544	1,198,556	714,575
OPERATING INCOME	537,270	627,875	252,469
OTHER (EXPENSES) INCOME			
Interest expense, net	(133,640)	(131,460)	(97,381)
Loss on early extinguishment of debt	—	—	(3,891)
(Loss) gain on derivatives	(131,212)	50,342	(66,135)
Change in TRA liability	—	(437)	35,847
Interest income	801	5,464	7,936
Other (expenses) income	(1,364)	(340)	783
Total other expenses, net	(265,415)	(76,431)	(122,841)
INCOME BEFORE INCOME TAXES	271,855	551,444	129,628
INCOME TAX EXPENSE	(61,437)	(105,475)	(5,708)
NET INCOME	210,418	445,969	123,920
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(35,206)	(76,842)	(17,146)
NET INCOME ATTRIBUTABLE TO PARSLEY ENERGY, INC. STOCKHOLDERS	$ 175,212	$ 369,127	$ 106,774
Net income per common share:			
Basic	$ 0.63	$ 1.36	$ 0.44
Diluted	$ 0.63	$ 1.35	$ 0.42
Weighted average common shares outstanding:			
Basic	279,636	272,226	240,733
Diluted	280,172	272,884	296,512

The accompanying notes are an integral part of these consolidated financial statements.

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(In thousands)

	Issued Shares						Shares				
	Class A common stock	Class B common stock	Class A common stock	Class B common stock	Additional paid in capital	(Accumulated deficit) retained earnings	Treasury stock	Treasury stock	Total stockholders' equity	Noncontrolling interest	Total equity
Balance at 12/31/2016	179,730	28,008	$ 1,797	$ 280	$ 2,151,197	$ (63,255)	139	$ (381)	$ 2,089,638	$ 340,668	$ 2,430,306
Issuance proceeds, net of underwriters discount and expenses	66,700	—	667		2,122,860	—	—	—	2,123,527	—	2,123,527
Shares of Class B common stock issued for acquisition	—	39,849	—	399	1,182,919	—	—	—	1,183,318	—	1,183,318
Change in equity due to issuance of PE Units by Parsley LLC	—	—	—	—	(915,749)	—	—	—	(915,749)	915,749	—
Exchange of PE Units and Class B common stock for Class A common stock	5,729	(5,729)	57	(57)	105,522	—	—	—	105,522	(105,522)	—
Issuance of restricted stock	228	—	3	—	(3)	—	—	—	—	370	370
Vesting of restricted stock units	33	—	—	—	—	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	12	(354)	(354)	—	(354)
Restricted stock forfeited	—	—	—	—	(14)	—	8	—	(14)	—	(14)
Stock-based compensation	—	—	—	—	19,633	—	—	—	19,633	—	19,633
Net income	—	—	—	—	—	106,774	—	—	106,774	17,146	123,920
Balance at 12/31/2017	252,420	62,128	$ 2,524	$ 622	$ 4,666,365	$ 43,519	159	$ (735)	$ 4,712,295	$ 1,168,411	$ 5,880,706
Exchange of PE Units and Class B common stock for Class A common stock	25,580	(25,580)	256	(256)	491,614	—	—	—	491,614	(491,614)	—
Change in net deferred tax liability due to exchange of PE Units	—	—	—	—	(13,841)	—	—	—	(13,841)	—	(13,841)
Distribution to owners from consolidated subsidiary	—	—	—	—	—	—	—	—	—	(1,962)	(1,962)
Issuance of restricted stock	803	—	8	—	(8)	—	—	—	—	—	—
Vesting of restricted stock units	926	—	9	—	(9)	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	435	(11,014)	(11,014)	—	(11,014)
Restricted stock forfeited	—	—	—	—	(967)	—	28	—	(967)	—	(967)
Conversion of restricted stock units to restricted stock awards	1,098	—	11	—	(11)	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	20,844	—	—	—	20,844	—	20,844
Net income	—	—	—	—	—	369,127	—	—	369,127	76,842	445,969
Balance at 12/31/2018	280,827	36,548	$ 2,808	$ 366	$ 5,163,987	$ 412,646	622	$ (11,749)	$ 5,568,058	$ 751,677	$ 6,319,735
Exchange of PE Units and Class B common stock for Class A common stock	1,128	(1,128)	11	(11)	18,939	—	—	—	18,939	(18,939)	—
Change in net deferred tax liability due to exchange of PE Units	—	—	—	—	(2,810)	—	—	—	(2,810)	—	(2,810)
Vesting of restricted stock units	305	—	3	—	(3)	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	311	(5,679)	(5,679)	—	(5,679)
Restricted stock forfeited	—	—	—	—	(1,315)	—	86	—	(1,315)	—	(1,315)
Stock-based compensation	—	—	—	—	21,997	—	—	—	21,997	—	21,997
Distribution to owners from consolidated subsidiary	—	—	—	—	—	—	—	—	—	(603)	(603)
Dividends and distributions declared ($0.06 per share and per unit, respectively)	—	—	—	—	—	(16,969)	—	—	(16,969)	(2,126)	(19,095)
Net income	—	—	—	—	—	175,212	—	—	175,212	35,206	210,418
Balance at 12/31/2019	282,260	35,420	$ 2,822	$ 355	$ 5,200,795	$ 570,889	1,019	$ (17,428)	$ 5,757,433	$ 765,215	$ 6,522,648

The accompanying notes are an integral part of these consolidated financial statements.

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2019	2018	2017
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 210,418	$ 445,969	$ 123,920
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	794,740	584,857	352,247
Leasehold abandonments and impairments	99,225	160,834	32,872
Accretion of asset retirement obligations	1,465	1,422	971
(Gain) loss on sale of property	(2,095)	(6,454)	14,332
Loss on early extinguishment of debt	—	—	3,891
Deferred income tax expense	61,437	105,475	5,752
Change in TRA liability	—	437	(35,847)
Stock-based compensation expense	20,682	19,877	19,619
Loss (gain) on derivatives	131,212	(50,342)	66,135
Net cash (paid) received for derivative settlements	(10,022)	6,279	16,172
Net cash paid for option premiums	(46,242)	(47,644)	(28,426)
Other	9,028	7,762	6,111
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(64,570)	(12,956)	(95,239)
Accounts receivable—related parties	(89)	294	(98)
Other current assets	3,690	(689)	45,417
Other noncurrent assets	524	(100)	(536)
Accounts payable and accrued expenses	49,466	(13,395)	122,992
Revenue and severance taxes payable	27,291	17,348	40,465
Other noncurrent liabilities	119	—	—
Net cash provided by operating activities	1,286,279	1,218,974	690,750
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development of oil and natural gas properties	(1,373,095)	(1,787,673)	(1,089,256)
Acquisitions of oil and natural gas properties	(52,020)	(136,972)	(2,192,093)
Additions to other property and equipment	(22,915)	(93,457)	(54,896)
Proceeds from sales of property, plant and equipment	41,326	233,647	30,537
Maturity of short-term investments	—	149,331	—
Purchases of short-term investments	—	—	(149,283)
Other	5,905	41,088	(1,869)
Net cash used in investing activities	(1,400,799)	(1,594,036)	(3,456,860)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under long-term debt	617,000	—	1,152,780
Payments on long-term debt	(617,000)	(2,888)	(74,769)
Payments on financing lease obligations	(2,746)	—	—
Debt issuance costs	—	(47)	(17,371)
Proceeds from issuance of common stock, net	—	—	2,123,344
Purchases of common stock	(5,679)	(11,014)	(354)
Dividends and distributions paid	(18,929)	—	—
Distributions to owner of consolidated subsidiary	(603)	(1,962)	—
Net cash (used in) provided by financing activities	(27,957)	(15,911)	3,183,630
Net (decrease) increase in cash and cash equivalents	(142,477)	(390,973)	417,520
Cash, cash equivalents, and restricted cash at beginning of year	163,216	554,189	136,669
Cash, cash equivalents, and restricted cash at end of year	$ 20,739	$ 163,216	$ 554,189
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ (129,387)	$ (127,668)	$ (63,170)
Cash received (paid) for income taxes	$ 302	$ —	$ (350)
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:			
Asset retirement obligations incurred, including changes in estimate	$ (4,087)	$ 2,111	$ 15,428
(Reductions) additions to oil and natural gas properties - change in capital accruals	$ (176)	$ (25,455)	$ 118,145
Net premiums paid on options that settled during the period	$ (43,278)	$ (71,566)	$ (37,103)
Common stock issued for oil and natural gas properties	$ —	$ —	$ 1,183,501

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1. ORGANIZATION AND NATURE OF OPERATIONS

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

Double Eagle Acquisition

On April 20, 2017, the Company, and its subsidiary, Parsley Energy LLC ("Parsley LLC"), completed the acquisition (the "Double Eagle Acquisition") of all of the interests in Double Eagle Lone Star LLC, DE Operating LLC, and Veritas Energy Partners, LLC (which were subsequently renamed Parsley DE Lone Star LLC, Parsley DE Operating LLC, and Parsley Veritas Energy Partners, LLC, respectively) from Double Eagle Energy Permian Operating LLC ("DE Operating"), Double Eagle Energy Permian LLC ("DE Permian"), and Double Eagle Energy Permian Member LLC (together with DE Operating and DE Permian, "Double Eagle"), as well as certain related transactions with an affiliate of Double Eagle. The aggregate purchase price for the Double Eagle Acquisition consisted of approximately (i) $1,395.6 million in cash and (ii) 39,848,518 units of Parsley LLC ("PE Units") and a corresponding 39,848,518 shares of Class B common stock, par value $0.01 per share, of the Company ("Class B common stock"). The Double Eagle Acquisition is discussed in further detail in *Note 6—Acquisitions of Oil and Natural Gas Properties*.

Public Offerings of Class A Common Stock

During 2017, the Company entered into multiple underwriting agreements to sell a total of 66,700,000 shares of Class A common stock, par value $0.01 per share, of the Company ("Class A common stock") (including 8,700,000 shares issued pursuant to the underwriters' option to purchase additional shares) in multiple underwritten public offerings (the "2017 Equity Offerings"). The 2017 Equity Offerings resulted in gross proceeds to the Company of approximately $2,168.9 million and net proceeds to the Company, after deducting underwriting discounts and commissions and offering expenses, of approximately $2,123.5 million. As discussed in *Note 6—Acquisitions of Oil and Natural Gas Properties*, a portion of the net proceeds was used to fund the cash portion of the purchase price for the Double Eagle Acquisition, a portion of the net proceeds was used to fund certain other acquisitions of oil and natural gas interests, and the remaining net proceeds were used to fund a portion of its capital program and for general corporate purposes.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

These consolidated financial statements include the accounts of (i) the Company, (ii) Parsley LLC, a direct majority owned subsidiary of the Company, (iii) the direct and indirect wholly owned subsidiaries of Parsley LLC, and (iv) Pacesetter Drilling, LLC ("Pacesetter"), an indirect, majority owned subsidiary of Parsley LLC, of which Parsley LLC owns, indirectly, a 63.0% interest. Parsley LLC also owns, indirectly, a 42.5% noncontrolling interest in Spraberry Production Services, LLC ("SPS"). The Company accounts for its investment in SPS using the equity method of accounting. All significant intercompany and intra-company balances and transactions have been eliminated.

Use of Estimates

These consolidated financial statements and related notes are presented in accordance with GAAP. Preparation in accordance with GAAP requires the Company to (i) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and by the SEC and (ii) make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The Company's management believes the major estimates and assumptions impacting the Company's consolidated financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depletion, depreciation and amortization ("DD&A") and impairment of proved oil and natural gas properties;
- impairment of undeveloped properties and other assets;
- depreciation of property and equipment; and
- valuation of commodity derivative instruments.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Cash and Cash Equivalents

The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Short-term Investments

Periodically, the Company invests in commercial paper with investment grade rated entities. The Company also periodically enters into time deposits with financial institutions. Commercial paper and time deposits are included in cash and cash equivalents if they have maturity dates that are less than three months at the date of purchase; otherwise, investments are reflected as short-term investments in the accompanying consolidated balance sheets based on their maturity dates. As of December 31, 2019, the Company had no short-term investments.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and crude oil, natural gas and natural gas liquids ("NGLs") production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due.

The Company recognizes an allowance for doubtful accounts in an amount equal to anticipated future uncollectible receivables. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. The Company had an allowance for doubtful accounts of $2.8 million at December 31, 2018. No allowance was deemed necessary at December 31, 2019.

Significant Customers

For the years ended December 31, 2019, 2018 and 2017, the following customers accounted for more than 10% of the Company's revenue:

	Year Ended December 31,		
	2019	2018	2017
Shell Trading (US) Company	55%	53%	62%
Lion Oil, Inc.	30%	22%	3%
Targa Pipeline Mid-Continent, LLC	8%	11%	13%

If a significant customer were to stop purchasing oil and natural gas from the Company, the Company's revenue could decline and the Company's operating results and financial condition could be harmed. While the Company believes that the Company could procure substitute or additional customers to offset the loss of one or more of the Company's current significant customers, there is no assurance that the Company would be successful in doing so on terms acceptable to the Company or at all.

Oil and Natural Gas Properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized.

Exploration and abandonment 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, impairment and amortization 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 a 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.

The following table summarizes exploration and abandonment costs incurred by the Company for the periods indicated (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Leasehold abandonments and impairments	$ 99,225	$ 160,834	$ 32,872
Geological and geophysical costs	978	1,479	5,429
Other	8	226	1,044
Total exploration and abandonment costs	$ 100,211	$ 162,539	$ 39,345

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties and mineral interests are depleted. Depletion of capitalized costs is calculated using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. Capitalized development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale of a complete or partial unit of a proved property, the Company determines the impact to the unit-of-production amortization rate. If the impact to the unit-of-production amortization rate is considered significant, the cost and related accumulated DD&A are removed from the property accounts and any gain or loss is recognized. If the impact to the unit-of-production amortization rate is not considered significant, the sale is accounted for as a normal retirement with no gain or loss recognized.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties by field. Whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, an impairment loss is indicated if the sum of the expected future cash flows related to proved properties in the applicable field is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset (discounted future cash flows). Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. See *Note 16—Disclosures About Fair Value of Financial Instruments* for additional information regarding the Company's impairment of proved oil and natural gas properties.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved costs are capitalized until reclassified from unproved properties to proved properties when proved reserves are discovered or are expensed as the leases expire or the Company specifically identifies leases that are probable of reverting to the lessor.

Unproved properties are assessed periodically for impairment on a property by property basis by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales, remaining lease terms and the expiration of all or a portion of such projects. The Company's periodic assessment also considers its ability to enter into leasehold exchange transactions and leasehold extensions that allow for higher concentrations of ownership and development. The Company recognizes impairment expense for unproved properties at the earlier of the time when the lease term or continuous development clause has expired or management estimates the lease will expire before it is drilled, sold or traded. The impairment of unproved oil and natural gas properties is recorded in *Exploration and abandonment costs* in the Company's consolidated statements of operations. Based on this assessment, the Company expensed $62.8 million and $127.0 million of undeveloped leasehold during the years ended December 31, 2019 and 2018, respectively, related to the expected future abandonment of expiring acreage. There were no such costs incurred during the year ended December 31, 2017. At December 31, 2019, the Company had $2.5 billion of undeveloped leasehold. Of the remaining undeveloped leasehold costs at December 31, 2019, $183.4 million is scheduled to expire in 2020. The leasehold expiring in 2020 relates to areas in which the Company is actively drilling. If the Company's drilling is not successful, this leasehold could become partially or entirely impaired.

The Company considers the following factors in its assessment of the impairment of unproved properties:

- the remaining length of unexpired term under its leases;
- its ability to actively manage and prioritize its capital expenditures to drill wells on undeveloped leases or make payments to extend leases that may be close to expiration;
- its ability to exchange leasehold positions with other companies that allow for higher concentrations of ownership and development potential; and
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases.

For sales of all of the Company's working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of less than all of the Company's working interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

As part of its business strategy, the Company regularly pursues the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The Company's most significant estimates in its allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Asset Retirement Obligations

For the Company, asset retirement obligations represent the future abandonment costs of tangible assets, namely the plugging and abandonment of wells and land remediation. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period. If the liability is settled for an amount other than the recorded amount, the difference is recorded in *Other income (expense)* in the Company's consolidated statements of operations.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including, but not limited to: the ultimate settlement amounts; inflation factors; credit-adjusted risk-free rates; timing of settlement; and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions affect the present value of the abandonment liability, the Company makes corresponding adjustments to both the asset retirement obligations and the related oil and natural gas property asset balance. These revisions result in prospective changes to DD&A expense and accretion of the discounted abandonment liability.

The following table summarizes the changes in the Company's asset retirement obligations for the periods indicated (in thousands):

	Year ended December 31,	
	2019	2018
Asset retirement obligations, beginning of year	$ 26,884	$ 27,170
Additional liabilities incurred	1,490	2,111
Dispositions of wells	(339)	(3,557)
Accretion expense	1,465	1,422
Liabilities settled upon plugging and abandoning wells	(484)	(262)
Revision of estimates	(5,577)	—
Asset retirement obligations, end of year	$ 23,439	$ 26,884

Other Property and Equipment, net

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or dispositions of assets, the cost and related accumulated depreciation are removed from the consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from two years to 35 years. Depreciation expense on other property and equipment was $18.9 million, $15.5 million and $11.5 million for the years ended December 31, 2019, 2018 and 2017, respectively. See *Note 16—Disclosures About Fair Value of Financial Instruments* for additional information regarding the Company's impairment of other property and equipment, net.

Materials and supplies are stated at the lower of cost or market and consist of oil and gas drilling or repair items such a tubing, casing and pumping units. These items are primarily acquired for use in future drilling or repair operations and are carried at lower of cost or market. "Market," in the context of valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint account under joint operating agreements to which the Company is a party. The Company evaluated materials and supplies based on current operations and determined that these materials and supplies would not be utilized in the current year and included them in noncurrent assets as non-depreciable other property, plant and equipment. See *Note 16—Disclosures About Fair Value of Financial Instruments* for additional information regarding the Company's impairment of materials and supplies.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with long-term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the Company has incurred interest expense.

Equity Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, the Company's share of investees' earnings or loss, after elimination of intra-company profit or loss, is generally recognized in the Company's consolidated statements of operations. The Company reviews its investments to determine if a non-temporary loss in value has occurred. If such loss has occurred, the Company would recognize an impairment provision. The Company did not recognize impairment for its equity investments during the years ended December 31, 2019, 2018 and 2017.

Derivative Instruments

The Company utilizes derivative financial instruments, including three-way collars, two-way collars and swap contracts to (i) reduce the effect of price volatility on the Company's oil and natural gas revenues and (ii) support its annual capital budgeting and expenditure plans.

The Company reports the fair value of derivatives on the consolidated balance sheets in derivative instrument assets and derivative instrument liabilities as either current or noncurrent. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual transactions and reports these on a gross basis by contract.

The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the Company's consolidated statements of operations in the period of change. Gains and losses resulting from the changes in fair value of derivatives are included in cash flows from operating activities.

Fair Value of Financial Instruments

Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the reporting date. The Company's assets and liabilities that are measured at fair value at each reporting date are classified according to a hierarchy that prioritizes inputs and assumptions underlying the valuation techniques. This fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs and consists of three broad levels:

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

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

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

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Deferred Loan Costs

Deferred loan costs are stated at cost, net of amortization, and are amortized to interest expense using the effective interest method over the life of the loan.

Revenue Recognition

Substantially all of the Company's revenue is from the sale of crude oil, natural gas and NGLs. See *Note 3—Revenue from Contracts with Customers* for additional information regarding the Company's revenue recognition.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for the benefit of all employees beginning on their date of hire. The plan allows eligible employees to contribute a portion of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to a certain percentage of an employee's contributions. For the years ended December 31, 2019, 2018 and 2017, the Company made contributions to the plan of $3.9 million, $3.8 million and $2.8 million, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends and its outlook for future years.

Earnings per Share

The Company uses the "if-converted" method to determine the potential dilutive effect of its Class B common stock and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock and restricted stock units.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Segment Reporting

Operating segments are defined as components of an enterprise (i) that engage in activities from which it may earn revenues and incur expenses and (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 the organization and management of the Company, the Company has only one reportable operating segment, which is oil and natural gas exploration and production. Other services that the Company engages in are ancillary to its oil and natural gas exploration and producing activities and it manages these services to support such activities.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current presentation.

Recent Accounting Pronouncements

Recently Issued but Not Yet Adopted Accounting Pronouncements

In June 2016, the FASB issued Accounting Standards Update ("ASU") 2016-13, *Financial Instruments—Credit Losses*. In May 2019, ASU 2016-13 was subsequently amended by ASU 2019-04, *Codification Improvements to Topic 326, Financial Instruments—Credit Losses and ASU 2019-05, Financial Instruments—Credit Losses (Topic 326)*: Targeted Transition Relief. ASU 2016-13, as amended, affects trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. ASU 2016-13 will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. In November 2019, the FASB issued ASU 2019-11, *Codification Improvements to Topic 326, Financial Instruments—Credit Losses.* ASU 2019-11 requires entities that did not adopt the amendments in ASU 2016-13 as of November 2019 to adopt 2019-11. This ASU contains the same effective dates and transition requirements as ASU 2016-13. This ASU did not have a material impact on the Company's consolidated financial statements as the Company does not have a history of material credit losses.

In December 2019, the FASB issued ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*. This ASU summarizes the FASB's recently issued ASU No. 2019-12, simplifying the Accounting for Income Taxes. The ASU enhances and simplifies various aspects of the income tax accounting guidance in Accounting Standards Codification ("ASC") Topic 740, *Income Taxes*. The amendments in this update are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The Company is in the process of evaluating the impact this guidance will have on the Company's consolidated financial statements and the timing of adoption.

Recently Adopted Accounting Pronouncements

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which supersedes the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, and most industry-specific guidance. The Company adopted this standard effective January 1, 2018 using the modified retrospective approach. As a result, the Company changed its accounting policy for revenue recognition, as discussed in *Note 3—Revenue from Contracts with Customers*. The Company also implemented processes and controls to ensure new contracts are reviewed for the appropriate accounting treatment and to generate the required disclosures under the standards.

In February 2016, the FASB issued ASU No. *2016-02, Leases (Topic 842)*, which requires lessees to recognize leases on balance sheet and disclose key information about leasing arrangements. Topic 842 was subsequently amended by ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*; ASU No. 2018-10, *Codification Improvements to Topic 842, Leases*; ASU No. 2018-11, Targeted Improvements; ASU No. 2018-20 Leases (Topic 842); and ASU No. 2020-02, *Financial Instruments—Credit Losses (Topic 326) and Leases (Topic 842)*. The standard establishes a right-of-use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. A modified retrospective transition approach is required, applying the standard to all leases existing at the date of initial application. An entity may choose to use either (1) its effective date or (2) the beginning of the earliest comparative period presented in the financial statements as its date of initial application. If an entity chooses the second option, the transition requirements for existing leases also apply to leases entered into between the date of initial application and the effective date. The entity must also recast its comparative period financial statements and provide the disclosures required by the standard for the comparative periods. The Company adopted the standard on January 1, 2019 using the modified retrospective transition approach, which allows the Company to apply the previous lease guidance and disclosure requirements under ASC Topic 840*, Leases* ("ASC 840"), in the comparative periods presented for the year of adoption. The adoption did not require an adjustment to beginning retained earnings for a cumulative effect adjustment.

The standard provides a number of optional practical expedients in transition. The Company has elected to apply the practical expedient to use hindsight with respect to determining lease term and in assessing any impairment of ROU assets for existing leases. The Company did not elect to apply the "package practical expedients." The standard also provides practical expedients for an entity's ongoing accounting. The Company elected the short-term lease recognition exemption for all leases that qualify. This means, for those leases that qualify, the Company did not recognize ROU assets or lease liabilities, and this includes not recognizing ROU assets or lease liabilities for existing short-term leases of those assets in transition. The Company has elected the practical expedient to not separate lease and non-lease components for all of its leases other than leases of vehicles.

Adoption of the standard resulted in the Company recording additional operating net ROU assets and lease liabilities of $143.9 million. The current portion of the operating lease liability is included in *Current operating lease liabilities* and the noncurrent portion of the operating lease liability is included in *Operating lease liabilities*, in each case, on the Company's consolidated balance sheets. Balances associated with finance leases have been reclassified to include the current portion in *Other current liabilities* and the noncurrent portion in *Financing lease liabilities* on the Company's consolidated balance sheets. The adoption of this standard did not materially impact the Company's consolidated statements of operations or cash flows. Please refer to *Note 9—Leases* for additional discussion.

In August 2018, the FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal—Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. This update requires the capitalization of implementation costs incurred in a hosting arrangement that is a service contract for internal-use software. Training and certain data conversion costs cannot be capitalized. The Company is required to expense the capitalized implementation costs over the term of the hosting agreement. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company adopted ASU 2018-15 prospectively as of October 1, 2019. The adoption of this guidance did not have a material effect on the Company's financial position, results of operation or cash flows.

NOTE 3. REVENUE FROM CONTRACTS WITH CUSTOMERS

In accordance with ASC Topic 606, *Revenue from Contracts with Customers* ("ASC 606"), effective January 1, 2018, the Company's revenue is measured based on considerations specified in contracts with its customers, excluding any sales incentives or amounts collected on behalf of third parties. The Company recognizes revenue when a performance obligation is satisfied by the transfer of control over a product to the ultimate customer. Sales of oil, natural gas and NGLs are recognized at the time that control of the product is transferred to the customer and collectability is reasonably assured. Generally, the pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the prices of the Company's oil, natural gas, and NGLs fluctuate to remain competitive with other available oil, natural gas, and NGLs supplies. The Company reports revenues disaggregated by product on its consolidated statements of operations.

Oil Sales

Under the Company's oil sales contracts, the Company sells oil production at or near the wellhead and the Company collects an agreed-upon index price, net of pricing differentials. The Company recognizes revenue at the net price received when control transfers to the purchaser at or near the wellhead.

Natural Gas and NGLs Sales

Under the Company's natural gas processing contracts, it delivers natural gas to a midstream processing company at the wellhead or the inlet of the midstream processing company's system. The midstream processing company gathers and processes the natural gas and remits proceeds to the Company for the resulting natural gas and NGLs sales. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction, which includes considerations of product redelivery, take-in-kind rights and risk of loss. For those contracts where the Company has concluded that control of the product transfers at the tailgate of the plant, meaning that the Company is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation and processing fees presented as transportation and processing costs on the Company's consolidated statements of operations. Alternatively, for those contracts where the Company has concluded control of the product transfers at the inlet of the plant, meaning that the Company is the agent and the midstream processing company is the Company's customer, the Company recognizes natural gas and NGLs sales based on the net amount of proceeds received from the midstream processing company. The Company has also determined that losses associated with shrinkage and line loss ("FL&U") occur prior to the change in control. As a result, natural gas and NGLs sales are presented net of FL&U costs. Revenues associated with natural gas and NGLs sales at the plant inlet are considered a single combined performance obligation. For the years ended December 31, 2019 and 2018, the applicable line items on the consolidated statements of operations include $8.7 million and $13.6 million of natural gas sales and $30.3 million and $59.5 million of NGLs sales, respectively, completed at the plant inlet.

Production Imbalances

Previously, the Company elected to utilize the entitlements method, which is no longer applicable, to account for natural gas production imbalances. The Company now utilizes the sales method to account for natural gas production imbalances; if the Company sells natural gas to a customer in excess of its entitled share of production, the Company is required to perform a principal versus agent analysis to determine whether it should record the gross amount of revenue and transportation and processing costs equal to the other owners' interests or recognize the net amount of revenue. In conjunction with the adoption of ASC 606, for the years ended December 31, 2019 and 2018, there were no material impacts to the financial statements due to this change in accounting for production imbalances.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature, with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASC 606-10-50-14, which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract Balances

Under the Company's product sales contracts, the Company invoices customers once performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements for certain natural gas and NGLs sales, however, may not be received for 30 to 90 days after the date production is delivered, and as a result the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the years ended December 31, 2019, 2018 and 2017, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

NOTE 4. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Instruments and Concentration of Risk

Objective and Strategy

The Company utilizes derivative financial instruments, including three-way collars and swap contracts to (i) reduce the effect of price volatility on the Company's oil and natural gas revenues and (ii) support the Company's annual capital budgeting and expenditure plans.

The Company uses collars and swaps to manage commodity price risk for its oil production. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract.

Additionally, the Company uses swap contracts to mitigate basis risk caused by the volatility of the Company's basis differentials. The oil swap contracts establish the differential between NYMEX WTI prices and the relevant price index at which oil production is sold. Natural gas swaps establish the differential Henry Hub prices and the relevant price index at which oil production is sold.

Oil Production Derivative Activities

The Company's material physical sales contracts governing its oil production are typically correlated with NYMEX WTI, including Cushing, Midland, Magellan East Houston ("MEH") and Brent oil prices. The Company uses put spread options, swaps and three-way collars to manage oil price volatility. The Company uses basis swap contracts to reduce basis risk between NYMEX WTI prices and the actual index prices at which the oil is sold.

As of December 31, 2019, the Company had the following outstanding oil derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

Three-way collars	Year Ending December 31, 2020		
	WTI Midland	WTI MEH	WTI Brent
Volume (MBbls)	7,800	15,900	3,450
Short call price (per Bbl)	$ 66.92	$ 73.24	$ 73.48
Long put price (per Bbl)	$ 56.00	$ 58.55	$ 62.26
Short put price (per Bbl)	$ 46.00	$ 48.55	$ 52.26

Oil swaps	Year Ending December 31, 2020	
	Volume (MBbls)	Fixed Price Swap (per Bbl)
Oil swap - Midland	600	$ 55.20
Oil swap - Houston	780	$ 56.30

Basis swaps	Year Ending December 31, 2020	
	Volume (MBbls)	Fixed Price Swap (per Bbl)
Basis swap - Midland-Cushing index(1)	900	$ 0.25

(1) Represents swaps that fix the basis differentials between the index prices at which the Company sells its oil and the Cushing WTI price.

The table above excludes 1,800 notional MBbls with a fair value of $9.0 million related to amounts recognized under master netting agreements with derivative counterparties associated with put spreads.

Natural Gas Production Derivative Activities

All material physical sales contracts governing the Company's natural gas production are tied directly or indirectly to NYMEX Henry Hub natural gas prices or regional index prices where the natural gas is sold. The Company uses swap contracts to manage natural gas price volatility.

The following table sets forth the volumes associated with the Company's outstanding natural gas derivative contracts expiring during the periods indicated and the weighted average natural gas prices for those contracts:

	Year Ending December 31, 2020	
	Volume (MMbtu)	Fixed Price Swap (per MMbtu)
Basis swap - Waha(1)	17,640,000	$ 0.88

(1) Represents swaps that fix the basis differentials between the index prices at which the Company sells its natural gas produced in the Permian Basin and NYMEX Henry Hub price.

Effect of Derivative Instruments on the Consolidated Financial Statements

All of the Company's derivatives are accounted for as non-hedge derivatives and therefore all changes in the fair values of its derivative contracts are recognized as gains or losses in the earnings of the periods in which they occur. The table below summarizes the Company's gains (losses) on derivative instruments for the years ended December 31, 2019, 2018 and 2017 (in thousands):

	Year Ending December 31,		
	2019	2018	2017
Changes in fair value of derivative instruments	$ (75,728)	$ 113,824	(44,702)
Net derivative settlements	(12,206)	8,084	15,670
Net premiums on options that settled during the period[1]	(43,278)	(71,566)	(37,103)
(Loss) gain on derivatives	$ (131,212)	$ 50,342	$ (66,135)

(1) The net premiums on options that settled during the period represents the cumulative cost of premiums paid and received on positions purchased and sold, which expired during the current period. These amounts are included in *(Loss) gain on derivatives* on the Company's consolidated statements of operations.

The Company classifies the fair value amounts of derivative assets and liabilities as gross current or noncurrent derivative assets or gross current or noncurrent derivative liabilities, whichever the case may be, excluding those amounts netted under master netting agreements. The fair value of the derivative instruments is discussed in *Note 16—Disclosures About Fair Value of Financial Instruments*. The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities at settlement or in the event of default under the agreements. Additionally, the Company maintains accounts with its brokers to facilitate financial derivative transactions in support of its risk management activities. Based on the value of the Company's positions in these accounts and the associated margin requirements, the Company may be required to deposit cash into these broker accounts. During the years ended December 31, 2019, 2018 and 2017, the Company did not receive or post any material margins in connection with collateralizing its derivative positions.

The following table presents the Company's net exposure from its offsetting derivative asset and liability positions, as well as option premiums payable and receivable as of the reporting dates indicated (in thousands):

	Gross Amount	Netting Adjustments	Net Exposure
December 31, 2019			
Derivative assets with right of offset or master netting agreements	$ 136,627	$ (8,995)	$ 127,632
Derivative liabilities with right of offset or master netting agreements	(167,517)	8,995	(158,522)
December 31, 2018			
Derivative assets with right of offset or master netting agreements	$ 236,431	$ (25,010)	$ 211,421
Derivative liabilities with right of offset or master netting agreements	(193,973)	25,010	(168,963)

Concentration of Credit Risk

The Company believes that it has limited credit risk with respect to its exchange-traded contracts, as such contracts are subject to financial safeguards and transaction guarantees through NYMEX. Over-the-counter traded options expose the Company to counterparty credit risk. These over-the-counter options are entered into with large multinational financial institutions with investment grade credit ratings or through brokers that require all the transaction parties to collateralize their open option positions. The gross and net credit exposure from the Company's commodity derivative contracts as of December 31, 2019 and 2018 is summarized in the preceding table.

The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines and assesses the impact on fair values of its counterparties' creditworthiness. The Company enters into International Swap Dealers Association Master Agreements ("ISDA Agreements") with its derivative counterparties. The terms of the ISDA Agreements provide the Company and its counterparties and brokers with rights of net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The Company routinely exercises its contractual right to offset realized gains against realized losses when settling with derivative counterparties. If the Company believes a counterparty's creditworthiness has declined or is suspect, it may seek to novate the applicable ISDA Agreement to another financial institution that has an ISDA Agreement in place with the Company. The Company did not incur any losses due to counterparty nonperformance during any of the years ended December 31, 2019, 2018 or 2017.

Credit Risk Related Contingent Features in Derivatives

Certain commodity derivative instruments contain provisions that require the Company to either post additional collateral or collateral support (including letters of credit, security interests in an asset, or a performance bond or guarantee), or immediately settle any outstanding liability balances, upon the occurrence of a specified credit risk related event. These events, which are set forth in the Company's existing commodity derivative contracts, include, among others, downgrades in the credit ratings of the Company and its affiliates, events of default under the Company's Revolving Credit Agreement (as defined in *Note 8—Debt*), and the release of collateral (other than as provided under the terms of the Revolving Credit Agreement). Although the Company could be required to post additional collateral or collateral support, or immediately settle any outstanding liability balances, under such conditions, the Company seeks to reduce its potential risk by entering into commodity derivative contracts with several different counterparties.

NOTE 5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment includes the following (in thousands):

	December 31, 2019	December 31, 2018
Oil and natural gas properties:		
Subject to depletion	$ 8,799,840	$ 6,659,444
Not subject to depletion		
Incurred in 2019	318,190	—
Incurred in 2018	402,584	677,920
Incurred in 2017 and prior	1,751,510	2,610,882
Total not subject to depletion	2,472,284	3,288,802
Oil and natural gas properties, successful efforts method	11,272,124	9,948,246
Less accumulated depreciation, depletion and impairment	(2,117,963)	(1,295,098)
Total oil and natural gas properties, net	9,154,161	8,653,148
Other property, plant and equipment	219,857	206,662
Less accumulated depreciation	(49,551)	(35,923)
Other property, plant and equipment, net	170,306	170,739
Total property, plant and equipment, net	$ 9,324,467	$ 8,823,887

Costs subject to depletion are proved costs and costs not subject to depletion are unproved costs and current drilling projects. At December 31, 2019 and 2018, the Company had excluded $2,472.3 million and $3,288.8 million of capitalized costs from depletion.

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and natural gas reserves related to the associated reservoir. Depletion expense on capitalized oil and natural gas properties was $775.8 million, $569.7 million and $340.8 million for the years ended December 31, 2019, 2018 and 2017, respectively. The Company had no exploratory wells in progress at December 31, 2019, 2018 or 2017.

Costs not subject to depletion primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established.

Costs not subject to depletion also include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $210.8 million and $275.3 million at December 31, 2019 and 2018, respectively. The Company anticipates that the $210.8 million associated with the wells in progress at December 31, 2019 will be transferred to costs subject to depletion during 2020. The $275.3 million associated with the wells in progress at December 31, 2018 was transferred to costs subject to depletion during 2019.

The Company capitalizes interest on expenditures made in connection with long-term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the company has incurred interest expense. There was no capitalized interest recorded during the years ended December 31, 2019, 2018 or 2017.

NOTE 6. ACQUISITIONS OF OIL AND NATURAL GAS PROPERTIES

The Company incurred costs of $52.0 million, $137.0 million and $194.5 million related to the purchase of leasehold acreage during the years ended December 31, 2019, 2018 and 2017, respectively. During the years ended December 31, 2019, 2018 and 2017, the Company reflected $27.1 million, $119.7 million and $176.5 million as part of costs not subject to depletion, respectively. During the years ended December 31, 2019, 2018 and 2017, the Company reflected $24.9 million, $17.3 million and $18.0 million as part of costs subject to depletion within its oil and natural gas properties, respectively.

In addition to the above described acquisition of leasehold acreage, during 2017, the Company acquired, from unaffiliated individuals and entities, interests in certain oil and natural gas properties through a number of separate, individually negotiated transactions, including the Double Eagle Acquisition (as defined in *Note 1—Organization and Nature of Operations*), for total consideration of $3,181.1 million. These acquisitions were accounted for using the acquisition method under ASC Topic 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair values as of the respective acquisition dates. The Company reflected $464.2 million of the total consideration paid as part of its costs subject to depletion within its oil and natural gas properties and $2,716.9 million as unproved leasehold costs within its oil and natural gas properties for year ended December 31, 2017. Excluding the Double Eagle Acquisition, the revenues and operating expenses attributable to these acquisitions during the years ended December 31, 2019, 2018 and 2017 were not material.

As described in *Note 1—Organization and Nature of Operations,* on April 20, 2017, the Company and Parsley LLC completed the Double Eagle Acquisition, as well as certain related transactions with an affiliate of Double Eagle. The aggregate consideration for the Double Eagle Acquisition, following post-closing adjustments, was $2,579.1 million, which consisted of (i) approximately $1,395.6 million in cash and (ii) 39,848,518 PE Units and a corresponding 39,848,518 shares of Class B common stock.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed as a result of the Double Eagle Acquisition (in thousands):

Cash	$	2,469
Receivables		20,756
Derivatives		3,970
Proved oil and natural gas properties		353,000
Unproved oil and natural gas properties		2,257,266
Total assets acquired		2,637,461
Accounts payable		(48,179)
Deferred tax liability		(10,167)
Total liabilities assumed		(58,346)
Estimated fair value of net assets acquired	$	2,579,115

During 2019, 2018 and 2017, the Company also exchanged certain unproved acreage and oil and natural gas properties with certain third parties, with no gain or loss recognized.

NOTE 7. SALES OF PROPERTY, PLANT AND EQUIPMENT

In 2019, the Company closed sales of certain leasehold acreage for proceeds of $38.5 million, including customary purchase price adjustments. Upon closing these sales, the Company recognized no gain or loss in accordance with the guidance for partial sales of oil and natural gas properties under ASC Topic 932, *Extractive Activities—Oil and Gas* (“ASC 932”).

In 2019, the Company completed the sale of certain property, plant and equipment for proceeds of $2.8 million. The Company recognized a $2.1 million gain on the sale.

In 2018, the Company closed the sale of certain leasehold, surface and mineral acreage for proceeds of $34.4 million, subject to customary purchase price adjustments. The Company recognized a $5.2 million gain on the sale.

In 2018, the Company also closed sales of certain leasehold acreage for proceeds of $188.2 million, including customary purchase price adjustments. As of December 31, 2017, the Company classified certain of these assets as held for sale. Upon closing these sales, the Company recognized no gain or loss in accordance with the guidance for partial sales of oil and natural gas properties under ASC 932.

In 2018, Pacesetter closed the sale of all of its physical assets for consideration equivalent to $13.1 million, consisting of $11.0 million in cash and a $2.1 million term loan that was repaid in the first quarter of 2019. Upon the liquidation of Pacesetter, its remaining assets will be distributed to its members, including Parsley Energy Operations, LLC (“Parsley Energy Operations”), a wholly owned subsidiary of Parsley LLC. The Company recognized a $1.2 million gain on the sale.

In 2017, the Company sold 21,939 gross (7,476 net) acres for total proceeds of $30.5 million and recognized a $14.3 million loss on the divestitures.

NOTE 8. DEBT

The following table provides a summary of the Company’s debt for the periods indicated (in thousands):

	December 31, 2019	December 31, 2018
Revolving Credit Agreement	$ —	$ —
6.250% senior unsecured notes due 2024	400,000	400,000
5.375% senior unsecured notes due 2025	650,000	650,000
5.250% senior unsecured notes due 2025	450,000	450,000
5.625% senior unsecured notes due 2027	700,000	700,000
Capital leases[1]	—	4,202
Total debt	2,200,000	2,204,202
Debt issuance costs on senior unsecured notes	(19,448)	(22,918)
Premium on senior unsecured notes	2,280	2,796
Less: current portion	—	(2,413)
Total long-term debt	$ 2,182,832	$ 2,181,667

(1) As a result of the implementation of ASU No. 2016-02, *Leases (Topic 842)*, as of December 31, 2019, capital leases have been reclassified to include the current portion in *Other current liabilities* and the noncurrent portion in *Financing lease liabilities* on the Company’s consolidated balance sheets.

Revolving Credit Agreement

On October 28, 2016, the Company and its subsidiary Parsley LLC entered into five-year revolving credit agreement with, among others, Wells Fargo Bank, National Association, as administrative agent (the “Revolving Credit Agreement”)

As of December 31, 2019, the Revolving Credit Agreement, as amended to date, provides a borrowing capacity equal to the lesser of (i) the borrowing base (which currently stands at $2.7 billion), (ii) the aggregate elected borrowing base commitments (which currently stand at $1.0 billion) and (iii) $5.0 billion. The Revolving Credit Agreement is secured by substantially all of Parsley LLC's and its restricted subsidiaries' assets.

There were no borrowings outstanding and $6.7 million in letters of credit outstanding under the Revolving Credit Agreement as of December 31, 2019, resulting in availability of approximately $993.3 million. Pro forma for the Jagged Peak Acquisition (as defined below), the 2028 Notes Offering (as defined below) and the 2024 Notes Redemption (as defined below), however, there were $365.7 million of borrowings outstanding with a weighted average interest rate of 3.13%. In connection with the completion of the Jagged Peak Acquisition, the Company repaid Jagged Peak's credit facility. The amount Parsley LLC is able to borrow under the Revolving Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Revolving Credit Agreement.

Borrowings under the Revolving Credit Agreement can be made in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBO rate plus an applicable margin ranging from 1.25% to 2.25%, depending on the percentage of the borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greater of (i) the prime rate of Wells Fargo, (ii) the federal funds effective rate plus 0.5% and (iii) the adjusted LIBO rate plus 1.0%, plus an applicable margin ranging from 0.25% to 1.25%, depending on the percentage of the borrowing base utilized. The Revolving Credit Agreement also provides for a commitment fee ranging from 0.375% to 0.500%, depending on the percentage of the borrowing base utilized. As of December 31, 2019, letters of credit outstanding under the Revolving Credit Agreement had a weighted average interest rate of 1.50%. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Parsley LLC is subject to various financial covenants under the Revolving Credit Agreement, which include, for example, the maintenance of the following financial ratios:

- a minimum current ratio (based on the ratio of consolidated current assets to consolidated current liabilities) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a maximum consolidated leverage ratio of not more than 4.0 to 1.0 as of the last day of any fiscal quarter for the four fiscal quarters ending on such date.

The Revolving Credit Agreement places restrictions on Parsley LLC and certain of its subsidiaries with respect to, for example, additional indebtedness, liens, dividends and other payments, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters. The Revolving Credit Agreement also places customary "holding company" restrictions on the activities of the Company. In addition, the Revolving Credit Agreement is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the administrative agent or the Majority Lenders (as defined in the Revolving Credit Agreement) may accelerate any amounts outstanding and terminate lender commitments.

6.250% Senior Unsecured Notes due 2024

On May 27, 2016, Parsley LLC and Parsley Finance Corp. ("Finance Corp." and together with Parsley LLC, the "Issuers") issued $200.0 million aggregate principal amount of 6.250% senior unsecured notes due 2024 (the "Initial 2024 Notes") in an offering that was exempt from registration under the Securities Act (the "Initial 2024 Notes Offering"). The Initial 2024 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $195.4 million.

On August 19, 2016, the Issuers issued an additional $200.0 million aggregate principal amount of 6.250% senior notes due 2024 (the "New 2024 Notes" and together with the Initial 2024 Notes, the "2024 Notes") at 102.000% of par, plus accrued and unpaid interest from May 27, 2016, in an offering that was exempt from registration under the Securities Act (the "New 2024 Notes Offering"). The New 2024 Notes Offering resulted in gross proceeds to the Company of $206.8 million, including a $4.0 million premium and $2.8 million of accrued and unpaid interest and net proceeds to the Company, after deducting accrued and unpaid interest, initial purchaser discounts and commissions and offering expenses, of approximately $199.6 million.

The New 2024 Notes were issued as additional notes under the indenture governing the Initial 2024 Notes. The New 2024 Notes have identical terms, other than the issue date, as the Initial 2024 Notes and the New 2024 Notes and the Initial 2024 Notes are treated as a single class of securities under the indenture governing the 2024 Notes. Interest is payable on the 2024 Notes semi-annually in arrears on each June 1 and December 1. The 2024 Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of the subsidiaries of Parsley LLC that guarantee the indebtedness under the Revolving Credit Agreement, other than Finance Corp. (the "Guarantor Subsidiaries"). The 2024 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2024 Notes.

At any time prior to June 1, 2019, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2024 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 106.250% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2024 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to June 1, 2019, the Issuers may, on any one or more occasions, redeem all or a part of the 2024 Notes for cash at a redemption price equal to 100% of the principal amount of the 2024 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to the date of redemption. On and after June 1, 2019, the Issuers may redeem the 2024 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 104.688% for the 12-month period beginning on June 1, 2019, 103.125% for the 12-month period beginning June 1, 2020, 101.563% for the 12-month period beginning on June 1, 2021, and 100% beginning on June 1, 2022, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2024 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

Utilizing net proceeds from the 2028 Notes Offering and borrowings under the Revolving Credit Agreement, the Company expects to redeem all of the 2024 Notes on March 7, 2020 at a redemption price of 104.688%, plus accrued and unpaid interest to the redemption date, pursuant to the terms of the indenture governing the 2024 Notes.

5.375% Senior Unsecured Notes due 2025

On December 13, 2016, the Issuers issued $650.0 million aggregate principal amount of 5.375% senior unsecured notes due 2025 (the "2025 Notes") in an offering that was exempt from registration under the Securities Act (the "2025 Notes Offering"). The 2025 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $644.1 million.

Interest is payable on the 2025 Notes semi-annually in arrears on each January 15 and July 15. The 2025 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The 2025 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2025 Notes.

At any time prior to January 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2025 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.375% of the principal amount of the 2025 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2025 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to January 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the 2025 Notes for cash at a redemption price equal to 100% of the principal amount of the 2025 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after January 15, 2020, the Issuers may redeem the 2025 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 104.031% for the 12-month period beginning on January 15, 2020, 102.688% for the 12-month period beginning January 15, 2021, 101.344% for the 12-month period beginning on January 15, 2022, and 100% beginning on January 15, 2023, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2025 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

5.250% Senior Unsecured Notes due 2025

On February 13, 2017, the Issuers issued $450.0 million aggregate principal amount of 5.250% senior unsecured notes due 2025 (the "New 2025 Notes") in an offering that was exempt from registration under the Securities Act (the "New 2025 Notes Offering"). The New 2025 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $444.1 million.

Interest is payable on the New 2025 Notes semi-annually in arrears on each February 15 and August 15. The New 2025 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The New 2025 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the New 2025 Notes.

At any time prior to August 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the New 2025 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.250% of the principal amount of the New 2025 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the New 2025 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to August 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the New 2025 Notes for cash at a redemption price equal to 100% of the principal amount of the New 2025 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after January 15, 2020, the Issuers may redeem the New 2025 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 103.938% for the 12-month period beginning on August 15, 2020, 102.625% for the 12-month period beginning August 15, 2021, 101.313% for the 12-month period beginning on August 15, 2022, and 100% beginning on August 15, 2023, plus accrued and unpaid interest to the redemption date.

The indenture governing the New 2025 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

5.625% Senior Unsecured Notes due 2027

On October 11, 2017, the Issuers issued $700.0 million aggregate principal amount of 5.625% senior unsecured notes due 2027 (the "2027 Notes" and together with the 2024 Notes, the 2025 Notes and the New 2025 Notes, the "Notes") in an offering that was exempt from registration under the Securities Act (the "2027 Notes Offering"). The 2027 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $692.1 million.

Interest is payable on the 2027 Notes semi-annually in arrears on each April 15 and October 15. The 2027 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The 2027 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2027 Notes.

At any time prior to October 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2027 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.625% of the principal amount of the 2027 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2027 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to October 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the 2027 Notes for cash at a redemption price equal to 100% of the principal amount of the 2027 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after October 15, 2022, the Issuers may redeem the 2027 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.813% for the 12-month period beginning on October 15, 2022, 101.875% for the 12-month period beginning October 15, 2023, 100.938% for the 12-month period beginning on October 15, 2024, and 100% beginning on October 15, 2025, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2027 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

At any time when the Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no default or event of default has occurred and is continuing, many of the foregoing covenants will be suspended. If the ratings on the Notes were to subsequently decline to below investment grade, the suspended covenants would be reinstated.

At December 31, 2019, the Company was in compliance with all required covenants under the Revolving Credit Agreement and each of the indentures governing the Notes.

Principal Maturities of Debt

Principal maturities of debt outstanding at December 31, 2019 are as follows (in thousands):

2020	$ —
2021	—
2022	—
2023	—
2024	400,000
Thereafter	1,800,000
Total	$ 2,200,000

Interest Expense

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

	Year ended December 31,		
	2019	2018	2017
Cash payments for interest	$ 129,387	$ 127,668	$ 63,170
Change in interest accrual	27	(437)	30,007
Amortization of deferred loan origination costs	4,742	4,745	3,985
Write-off of deferred loan origination costs	—	—	735
Amortization of bond premium	(516)	(516)	(516)
Total interest expense, net	$ 133,640	$ 131,460	$ 97,381

NOTE 9. LEASES

The Company has entered into operating leases for drilling rigs, real estate, and other field and office equipment, as well as finance leases for vehicles. The Company's leases have lease terms that include options to extend for up to 14 years, and some of which include options to terminate within one year. The exercise of lease renewal and termination options are at the Company's sole discretion. For purposes of calculating operating lease liabilities, the Company's leases are deemed not to include an option to extend the lease term until it is reasonably certain that the Company will exercise that option. Certain of the Company's finance leases also include an option to purchase the leased asset. The Company determines whether a contract arrangement contains a lease at inception. The lease classification and lease measurement are determined upon lease commencement. The lease commencement date is evaluated based on when the key lease terms are available and when the Company takes possession of the underlying asset. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants. ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. The lease payments represent gross payments to vendors which, for certain of the Company's operating assets, are offset by amounts received from other working interest owners. Because the majority of the Company's leases do not provide an implicit rate of return, the Company uses its incremental borrowing rate based on the information available at the commencement date of the lease in determining the present value of lease payments. The incremental borrowing rate is not a quoted rate and is derived by applying a spread over U.S. Treasury rates with a similar duration to the Company's lease payments. The spread utilized is based on the Company's one-year borrowing cost assuming the midpoint of applicable margins under the Revolving Credit Agreement. The Company has operating lease agreements with lease and non-lease components that are accounted for as a single lease component. For vehicle leases, the Company accounts for the lease and non-lease components separately. The Company subleases certain of its real estate to third parties for office and parking space.

The Company recognizes lease costs on a straight-line basis over the term of the lease. The depreciable life of assets is limited by the non-cancellable term of the lease, unless there is a transfer of title or purchase option reasonably certain of exercise. The components of the Company's lease costs as of December 31, 2019 were as follows (in thousands):

	Year Ended December 31, 2019
Finance lease costs:	
Amortization of right-of-use assets	$ 2,779
Interest on lease liabilities	242
Operating lease costs(1)	92,709
Short-term lease costs(2)	20,578
Variable lease costs(3)	29,024
Sublease income	(463)
Total lease costs	$ 144,869

(1) For the year ended December 31, 2019, operating lease costs are included in the following line items on the Company's consolidated financial statements: $69.1 million are capitalized as part of *Oil and natural gas properties*; $10.1 million, are included in *General and administrative expenses*; $7.1 million are included in *Lease operating expenses*; and $6.4 million are included in *Other operating expenses*.

(2) Short-term lease costs represent costs related to leases with a contract term of one year or less. For the year ended December 31, 2019, short-term lease costs are included in the following line items on the Company's consolidated financial statements: $3.1 million are capitalized as part of *Oil and natural gas properties;* and $17.5 million are included in *Lease operating expenses*.

(3) Variable lease costs that are not dependent on an index or rate are not included in the lease liability or ROU assets. For the year ended December 31, 2019, variable lease costs are included in the following line items on the Company's consolidated financial statements: $19.6 million are capitalized as part of *Oil and natural gas properties* and $9.4 million are included in *General and administrative expenses.*

Supplemental cash flow information related to the Company's leases as of December 31, 2019 was as follows (in thousands):

Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows from operating leases	$	23,644
Investing cash outflows from operating leases	$	71,487
Operating cash outflows from finance leases	$	242
Financing cash outflows from finance leases	$	2,746
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	109,681
Finance leases	$	2,618

Supplemental balance sheet information related to the Company's leases as of December 31, 2019 was as follows (in thousands):

Operating leases		
Assets		
Operating lease assets, net of accumulated depreciation	$	128,529
Liabilities		
Current operating lease liabilities		(61,198)
Operating lease liabilities		(69,195)
Total operating lease liabilities	$	(130,393)
Finance leases		
Assets		
Property and equipment, gross	$	8,418
Accumulated depreciation		(5,063)
Property and equipment, net	$	3,355
Liabilities		
Other current liabilities	$	(2,101)
Financing lease liabilities		(1,320)
Total finance liabilities	$	(3,421)
Weighted average remaining lease term (in years)		
Operating leases		3.0
Finance leases		1.8
Weighted average discount rate		
Operating leases		4.7%
Finance leases		5.6%

Maturities of Lease Liabilities

Maturities of the Company's lease liabilities as of December 31, 2019 were as follows (in thousands):

	Operating leases	Finance leases
2020	$ 65,408	$ 2,234
2021	36,386	1,176
2022	16,240	184
2023	8,792	13
2024	7,750	—
Thereafter	5,063	—
Total lease payments	$ 139,639	$ 3,607
Less imputed interest	(9,246)	(186)
Total lease obligations	$ 130,393	$ 3,421
Less: Current obligations	(61,198)	(2,101)
Long-term lease obligations	$ 69,195	$ 1,320

In addition, the Company has entered into a contract for a 12-year real estate lease that will commence during fiscal year 2021. On commencement of the lease, the Company will record additional operating lease liabilities of approximately $180.5 million.

As of December 31, 2018, minimum future contractual payments for long-term operating leases under the scope of ASC 840 were as follows (in thousands):

	Operating leases(1)	Finance leases
2019	$ 71,998	$ 2,413
2020	39,403	1,288
2021	26,658	436
2022	22,473	51
2023	21,822	14
Thereafter	148,508	—
Total lease payments	$ 330,862	$ 4,202

(1) Operating leases included minimum future contractual payments for long-term operating leases that have not commenced.

NOTE 10. EQUITY

Preferred Stock

Pursuant to the Company's amended and restated certificate of incorporation, the Company's board of directors may, subject to any limitations prescribed by law but without further stockholder approval, establish and issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, up to an aggregate of 50.0 million shares. The Company had no shares of preferred stock outstanding at December 31, 2019 and 2018.

Class A Common Stock

The Company had 281.2 million shares of Class A common stock outstanding as of December 31, 2019, which includes 0.4 million shares of time-based restricted stock ("RSAs") and 0.8 million shares of performance-based restricted stock ("PSAs"). Holders of Class A common stock are entitled to one vote per share on all matters to be voted upon by the stockholders and are entitled to ratably receive dividends when and if declared by the Company's board of directors. Upon liquidation, dissolution, distribution of assets or other winding up, the holders of Class A common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and the liquidation preference of any of the Company's outstanding shares of preferred stock.

Class B Common Stock

The Company had 35.4 million shares of its Class B common stock outstanding as of December 31, 2019. Holders of the Class B common stock are entitled to one vote per share on all matters to be voted upon by the stockholders. Holders of Class A common stock and Class B common stock vote together as a single class on all matters presented to the Company's stockholders for their vote or approval, except with respect to the amendment of certain provisions of the Company's amended and restated certificate of incorporation that would alter or change the powers, preferences or special rights of the Class B common stock so as to affect them adversely, which amendments must be by a majority of the votes entitled to be cast by the holders of the shares affected by the amendment, voting as a separate class, or as otherwise required by applicable law.

Holders of Class B common stock do not have any right to receive dividends, unless the dividend consists of shares of Class B common stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class B common stock paid proportionally with respect to each outstanding share of Class B common stock and a dividend consisting of shares of Class A common stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class A common stock on the same terms is simultaneously paid to the holders of Class A common stock. Holders of Class B common stock do not have any right to receive a distribution upon a liquidation or winding up of the Company.

Earnings per Share

Basic earnings per share ("EPS") measures the performance of an entity over the reporting period. Diluted earnings per share measures the performance of an entity over the reporting period while giving effect to all potentially dilutive common shares that were outstanding during the period. The Company uses the "if-converted" method to determine the potential dilutive effect of exchanges of outstanding PE Units (and corresponding shares of Class B common stock), and the treasury stock method to determine the potential dilutive effect of vesting of its outstanding restricted stock and restricted stock units. For the years ended December 31, 2019 and 2018, Class B common stock was not recognized in dilutive EPS calculations as the effect would have been antidilutive.

The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of shares of common stock outstanding for the period:

	Year ended December 31,		
	2019	2018	2017
Basic EPS (in thousands, except per share data)			
Numerator:			
Basic net income attributable to Parsley Energy, Inc. Stockholders	$ 175,212	$ 369,127	$ 106,774
Denominator:			
Basic weighted average shares outstanding	279,636	272,226	240,733
Basic EPS attributable to Parsley Energy, Inc. Stockholders	$ 0.63	$ 1.36	$ 0.44
Diluted EPS			
Numerator:			
Net income attributable to Parsley Energy, Inc. Stockholders	175,212	369,127	106,774
Effect of conversion of the shares of Company's Class B common stock to shares of the Company's Class A common stock	—	—	17,646
Diluted net income attributable to Parsley Energy, Inc. Stockholders	$ 175,212	$ 369,127	$ 124,420
Denominator:			
Basic weighted average shares outstanding	279,636	272,226	240,733
Effect of dilutive securities:			
Class B common stock	—	—	54,665
Time-Based Restricted Stock and Time-Based Restricted Stock Units	536	658	1,114
Diluted weighted average shares outstanding(1)	280,172	272,884	296,512
Diluted EPS attributable to Parsley Energy, Inc. Stockholders	$ 0.63	$ 1.35	$ 0.42

(1) As of December 31, 2019, there were 790,507 and 358,240 PSAs and performance-based restricted stock units ("PSUs"), respectively. As of December 31, 2018 and 2017, there were 1,338,439 PSAs and 640,062 PSUs, respectively. PSAs and PSUs could vest in the future based on predetermined performance and market goals. PSAs and PSUs were not included in the computation of EPS for the years ended December 31, 2019, 2018 and 2017, respectively because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the contingency period.

Dividends

During the third quarter of 2019, the Company's board of directors initiated the Company's first quarterly dividend, payable on issued and outstanding shares of Class A common stock, and, in its capacity as the managing member of Parsley LLC, a corresponding distribution from Parsley LLC to holders of PE Units (each, a "PE Unitholder"). The portion of the Parsley LLC distribution attributable to PE Units held by the Company was used to fund the quarterly dividend on issued and outstanding shares of Class A common stock. As described in these financial statements, as the context requires, dividends paid to holders of Class A common stock and distributions paid to PE Unitholders (other than Parsley Energy, Inc.) may be referred to collectively as "dividends."

Dividends declared are recorded as a reduction of retained earnings, to the extent that retained earnings were available at the beginning of the reporting period, with any excess recorded as a reduction in paid capital. Dividends paid to PE Unitholders (other than the Company) are treated as a partnership distribution from Parsley LLC and are recorded as a reduction in noncontrolling interests.

The following table sets forth information with respect to cash dividends and distributions declared by the Company's board of directors during 2019, on its own behalf and in its capacity as the managing member of Parsley LLC, on issued and outstanding shares of Class A common stock and PE Units:

Declaration Date	Record Date	Payment Date	Dividend/Distribution Amount(1)	Total Dividend/ Distribution Payment(2) (in thousands)
August 6, 2019	September 20, 2019	September 30, 2019	$ 0.03	$ 9,547
November 5, 2019	December 10, 2019	December 20, 2019	$ 0.03	$ 9,548

(1) Per share of Class A common stock and per PE Unit. The portion of the Parsley LLC distribution attributable to PE Units held by the Company was used to fund the quarterly dividend on issued and outstanding shares of Class A common stock.

(2) Reflects total cash dividend and distribution payments made, or to be made, to holders of Class A common stock and PE Unitholders (other than the Company) as of the applicable record date.

The Company did not pay dividends on Class A common stock or distributions on PE Units during the years ended December 31, 2018 or 2017.

Noncontrolling Interests

As a result of the 2017 Equity Offerings, the Company's ownership of Parsley LLC increased from 86.5% to 89.8% and the PE Unitholders' (other than the Company) ownership of Parsley LLC decreased from 13.5% to 10.2%. Subsequently, as a result of the consummation of the Double Eagle Acquisition, the Company's ownership of Parsley LLC decreased from 89.8% to 78.4% and the PE Unitholders' (other than the Company) ownership of Parsley LLC increased from 10.2% to 21.6%. Any impact to additional paid in capital as a result of the 2017 Equity Offerings was completely offset by a valuation allowance.

During the year ended December 31, 2017, certain PE Unitholders exercised their exchange right under the Parsley LLC Agreement (as defined below), collectively electing to exchange an aggregate of 5.7 million PE Units (and a corresponding number of shares of Class B common stock) for an aggregate of 5.7 million shares of Class A common stock (collectively, the "2017 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unitholders in satisfaction of their elections. As a result of the 2017 Exchanges, the Company's ownership of Parsley LLC increased from 78.4% to 80.2% and the PE Unitholders' (other than the Company) ownership of Parsley LLC decreased from 21.6% to 19.8%. The "Parsley LLC Agreement" refers to the Limited Liability Company Agreement of Parsley LLC, dated June 11, 2013, thereafter amended and restated by the Second Amended and Restated Limited Liability Company Agreement, dated May 29, 2014, thereafter amended and restated by the Third Amended and Restated Limited Liability Company Agreement, dated February 20, 2019, thereafter amended and restated by the Fourth Amended and Restated Limited Liability Company Agreement, dated July 22, 2019, as in effect as of the applicable date.

During the year ended December 31, 2018, certain PE Unitholders exercised their exchange right under the Parsley LLC Agreement, collectively electing to exchange an aggregate of 25.6 million PE Units (and a corresponding number of shares of Class B common stock) for an aggregate of 25.6 million shares of Class A common stock (collectively, the "2018 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unitholders in satisfaction of their elections. As a result of the 2018 Exchanges, the Company's ownership in Parsley LLC increased from 80.2% to 88.5% and the ownership of the PE Unitholders (other than the Company) in Parsley LLC decreased from 19.8% to 11.5%.

During the year ended December 31, 2019, certain PE Unitholders, including an executive officer of the Company, exercised their exchange right under the Parsley LLC Agreement, collectively electing to exchange 1.1 million PE Units (and a corresponding number of shares of Class B common stock) for 1.1 million shares of Class A common stock (collectively, the "2019 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unitholders in satisfaction of their elections. As a result of the 2019

Exchanges, the Company's ownership in Parsley LLC increased from 88.5% to 88.8% and the ownership of the PE Unitholders (other than the Company) in Parsley LLC decreased from 11.5% to 11.2%.

Because these changes in the Company's ownership interest in Parsley LLC did not result in a change of control, the transactions were accounted for as equity transactions under ASC Topic 810, *Consolidation*, which requires that any differences between the carrying value of the Company's basis in Parsley LLC and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. The Company has consolidated the financial position and results of operations of Parsley LLC and records noncontrolling interests for the economic interests in Parsley LLC held by PE Unitholders (other than the Company).

The following table summarizes the net income (loss) attributable to noncontrolling interests:

	Year ended December 31,		
	2019	2018	2017
		(in thousands)	
Net income (loss) attributable to the noncontrolling interests of:			
Parsley LLC	$ 35,231	$ 76,079	$ 17,645
Pacesetter Drilling, LLC	(25)	763	(499)
Total net income attributable to noncontrolling interests	$ 35,206	$ 76,842	$ 17,146

As discussed in *Note 2—Summary of Significant Accounting Policies—Principles of Consolidation*, Parsley LLC owns, indirectly a 63.0% interest in Pacesetter. The remaining 37.0%interest in Pacesetter is reflected by the Company as a noncontrolling interest. Following the sale of Pacesetter's physical assets in 2018, discussed in *Note 7—Sales of Property, Plant and Equipment*, Pacesetter made distributions to its equity holders of $0.6 million and $2.0 million during the years ended December 31, 2019 and 2018, respectively.

NOTE 11. STOCK-BASED COMPENSATION

In connection with the Company's initial public offering (the "IPO"), the Company adopted the Parsley Energy, Inc. 2014 Long-Term Incentive Plan ("LTIP") for employees, consultants and directors of the Company who perform services for the Company. The shares to be delivered under the LTIP shall be made available from (i) authorized but unissued shares, (ii) shares held as treasury stock or (iii) previously issued shares reacquired by the Company including shares purchased on the open market. A total of 12.7 million shares of Class A common stock have been authorized for issuance under the LTIP. At December 31, 2019, the Company had 7.9 million shares of Class A common stock available for future grant.

On February 12, 2018, the PSUs granted in 2016 and 2017 were converted into PSAs at 200% of the target payout for such awards. Similarly, certain of the time-based restricted stock units ("RSUs") granted in 2016 were also converted to RSAs on February 12, 2018. Upon conversion, the PSAs and RSAs became economically identical to the pre-conversion awards with the same material terms and conditions, including vesting schedules and performance criteria.

Stock-based compensation expense recorded for each type of stock-based compensation award for the years ended December 31, 2019, 2018 and 2017 is as follows (in thousands):

	Year ended December 31,		
	2019	2018	2017
Time-based restricted stock(1)	$ 4,256	$ 7,200	$ 5,492
Time-based restricted stock units(1)	9,395	5,690	7,778
Performance-based restricted stock(2)	4,332	6,987	6,349
Performance-based restricted stock units	2,699	—	—
Total stock-based compensation	$ 20,682	$ 19,877	$ 19,619

(1) Stock-based compensation expense relating to RSAs and RSUs with ratable vesting is recognized on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

(2) Includes stock-based compensation expense related to historical PSUs prior to the conversion of such awards to PSAs.

Stock-based compensation is included in *General and administrative expenses* on the Company's consolidated statements of operations.

Time-Based Restricted Stock

RSAs are awards of Class A common stock that are legally issued and outstanding. RSAs are subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient ceases providing services to the Company prior to the lapse of the restrictions. The stock-based compensation expense for these awards was determined using the closing price on the date of grant applied to the total number of shares that were anticipated to fully vest. The following table summarizes the RSA activity for the year ended December 31, 2019:

	Time-Based Restricted Stock	Grant Date Fair Value
Outstanding at January 1, 2019	715,852	$ 23.44
Forfeited	(19,763)	$ 25.55
Vested	(309,699)	$ 19.32
Outstanding at December 31, 2019	386,390	$ 26.64

Time-Based Restricted Stock Units

RSUs represent the right to receive shares of Class A common stock at the end of the vesting period in an amount equal to the number of RSUs that vest. RSUs are subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient ceases providing services to the Company prior to the lapse of the restriction. The stock-based compensation expense of such RSUs was determined using the closing price on the date of grant applied to the total number of shares that were anticipated to fully vest. The following table summarizes the RSU activity for the year ended December 31, 2019:

	Time-Based Restricted Stock Units	Grant Date Fair Value
Outstanding at January 1, 2019	723,354	$ 23.78
Awards granted	992,825	$ 17.83
Forfeited	(174,643)	$ 20.82
Vested	(301,078)	$ 19.43
Outstanding at December 31, 2019	1,240,458	$ 20.48

Performance-Based Restricted Stock Units and Performance-Based Restricted Stock Awards

During 2019, 2018 and 2017, PSUs and PSAs were granted with a three-year performance period. The terms and conditions of the PSAs and PSUs allow for vesting of the awards ranging between forfeiture and 200% of target. The vesting level is calculated based on the actual total stockholder return achieved during the performance period compared to the total stockholder return of a predetermined peer group. The fair value of such PSUs or PSAs was determined using a Monte Carlo simulation and will be recognized over the applicable three-year performance period. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award to calculate the fair value of the award. Expected volatilities in the model were estimated using a historical period consistent with the performance period of approximately three years. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the grant. The Company used the following assumptions to estimate the fair value of PSUs and PSAs granted during the periods indicated:

	Year Ended December 31,		
	2019	2018	2017
Risk-free interest rate	2.46%	2.25%	1.45%
Range of volatilities	32.4% - 61.8%	34.4% - 82.2%	37.7% - 79.5%

During 2018, outstanding PSUs were converted into PSAs with the same terms and conditions, including vesting provisions, as the historical PSUs. Upon conversion, the PSAs became economically identical to the pre-conversion PSUs originally granted. Due to the nature of restricted stock awards, the number of as-converted PSAs is equal to the maximum number of PSAs (i.e., 200% of the target number of PSUs) that may vest. However, the PSAs will only vest based on actual performance achievement during the applicable performance period to the same extent as the pre-conversion PSUs would have vested, and any such PSAs that do not vest will be forfeited. No accounting charge was taken in connection with this conversion.

The following table summarizes the PSU activity for the year ended December 31, 2019:

	Performance-Based Restricted Stock Units	Grant Date Fair Value
Outstanding at January 1, 2019	—	$ —
Awards granted	376,166	$ 24.05
Vested	(2,455)	$ 24.05
Forfeited	(15,471)	$ 24.05
Outstanding at December 31, 2019	358,240	$ 24.05

The following table summarizes the PSA activity for the year ended December 31, 2019:

	Performance-Based Restricted Stock	Grant Date Fair Value
Outstanding at January 1, 2019	1,338,439	$ 15.07
Vested	(481,820)	$ 13.07
Forfeited	(66,112)	$ 15.74
Outstanding at December 31, 2019	790,507	$ 16.24

The following table reflects the future stock-based compensation expense to be recorded for the stock-based compensation awards that were outstanding at December 31, 2019 (in thousands):

	Time-Based Restricted Stock	Time-Based Restricted Stock Units	Performance-Based Restricted Stock	Performance-Based Restricted Stock Units	Total
2020	$ 1,933	$ 7,324	$ 2,111	$ 2,992	$ 14,360
2021	193	4,455	—	2,984	7,632
2022	—	458	—	—	458
Total	$ 2,126	$ 12,237	$ 2,111	$ 5,976	$ 22,450

NOTE 12. INCOME TAXES

The Company is a corporation and is subject to U.S. federal income tax and the Texas Margins Tax. On December 22, 2017, Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”), was enacted by the U.S. government. The Tax Act made broad and complex changes to the U.S. corporate income tax code. Among other changes, the Tax Act: (i) reduced the U.S. federal corporate income tax rate from 35% to 21%; (ii) repealed the corporate alternative minimum tax and provides for a refund of previously accrued alternative minimum tax credits; (iii) modified the provisions relating to the limitations on deductions for executive compensation of publicly traded corporations; (iv) enacted new limitations regarding the deductibility of interest expense; and (v) imposed new limitations on the utilization of net operating losses arising in taxable years beginning after December 31, 2017.

GAAP requires that the impact of tax legislation be recognized in the period in which the law was enacted. As a result of the Tax Act, the Company remeasured its deferred tax assets and liabilities based on the federal income and state income tax rates at which they are now expected to reverse, and they now generally reflect a federal income tax rate of 21%. The enacted rate change resulted in a non-cash increase of approximately $23.9 million to the Company’s income tax provision, a corresponding reduction of $23.9 million to the Company’s net noncurrent deferred tax asset balance, and a reduction in valuation allowance of $24.3 million at December 31, 2017. There were no adjustments recorded to these estimates during the years ended December 31, 2019 or 2018.

The Company’s effective combined U.S. federal and state income tax rate as of December 31, 2019, 2018 and 2017 was 22.6%, 19.1% and 4.4% respectively.

During the years ended December 31, 2019, 2018 and 2017, the Company recognized income tax expenses of $61.4 million, $105.5 million and $5.7 million, respectively. Total income tax differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the change in the valuation allowance, the change in the TRA liability, state taxes and the impact of income (loss) attributable to noncontrolling ownership interests.

At December 31, 2019, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. The Company's policy is to record interest and penalties relating to uncertain tax positions in income tax expense.

The components of the income tax expense were as follows for the periods indicated (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Federal:			
Current	$ —	$ —	$ (44)
Deferred	58,310	101,023	(423)
Total federal	58,310	101,023	(467)
State, net of federal benefit:			
Deferred	3,127	4,452	6,175
Total state	3,127	4,452	6,175
Income tax expense	$ 61,437	$ 105,475	$ 5,708

The following table reconciles the income tax expense with income tax expense at the federal statutory rate for the periods indicated (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Income before income taxes	$ 271,855	$ 551,444	$ 129,628
Less: net income before income taxes attributable to noncontrolling interest	(35,710)	(77,446)	(18,725)
Income attributable to Parsley Energy, Inc. Stockholders before income taxes	236,145	473,998	110,903
Income taxes at the federal statutory rate	49,591	99,539	38,816
State income taxes, net of federal benefit	3,127	4,452	6,175
Provision to return adjustment	2,352	(1,018)	178
Permanent and other	(140)	(2,285)	166
TRA liability change	—	92	(12,547)
Valuation allowance	6,507	4,695	(26,657)
Valuation allowance due to the reduction in federal statutory rate	—	—	(24,356)
Income tax provision due to change in federal statutory rate	—	—	23,933
Income tax expense	$ 61,437	$ 105,475	$ 5,708
Net income attributable to Parsley Energy, Inc. Stockholders	$ 175,212	$ 369,127	$ 106,774
Net income attributable to noncontrolling interest	$ 35,206	$ 76,842	$ 17,146

As of December 31, 2019, the Company had approximately $0.4 million of alternative minimum tax credits available that are expected to be refunded between 2020 and 2021. In addition, the Company had approximately $587.1 million of federal net operating loss carryovers that expire during the years 2034 through 2037. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforwards is determined to not be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. As of December 31, 2019, the Company had a valuation allowance of $20.4 million as a result of management's assessment of the realizability of deferred tax assets.

Internal Revenue Code of 1986, as amended ("Section 382"), addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. The Company does not believe it experienced an ownership change within the meaning of IRC Section 382 during 2019. Even if the Company did experience an ownership change in 2019, any resulting limitation on the use of the Company's net operating loss carryforwards under Section 382 would not result in a current federal tax liability at December 31, 2019, and the Company does not believe that the resulting Section 382 annual limitation would prevent its utilization of net operating losses prior to their expiration.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	December 31, 2019	December 31, 2018
Assets:		
Asset retirement obligations	$ 4,923	$ 4,723
Deferred stock-based compensation	7,196	6,718
Derivative fair value loss	5,985	—
Accrued compensation	5,642	4,650
Lease liabilities	27,089	—
Earnings in investment in subsidiary	182	—
Other	1,910	—
Net operating loss carryforward	170,520	299,250
Total deferred tax assets	223,447	315,341
Less: Valuation allowance	(20,382)	(13,862)
Net deferred tax assets	203,065	301,479
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(369,474)	(423,102)
Derivative fair value gain	—	(9,450)
Earnings in investment in subsidiary	—	(156)
Lease right-of-use assets	(27,000)	—
Other	—	(294)
Total deferred tax liabilities	(396,474)	(433,002)
Net deferred tax liability	$ (193,409)	$ (131,523)

With respect to income taxes, the Company's policy is to account for interest charges as *Interest expense, net* and any penalties as *Other income (expenses)* in the Company's consolidated statements of operations. The Company files income tax returns at the federal level and at the state level (Texas), and a number of such returns remain open for examination. The Company's earliest open years in its key jurisdictions are as follows:

U.S. Federal	2016
State of Texas	2015

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2019, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions.

Tax Receivable Agreement

In connection with the IPO, on May 29, 2014, the Company entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC and certain PE Unitholders (each such person and any permitted transferee, a "TRA Holder"), including certain executive officers. The TRA generally provides for the payment by the Company of 85% of the net cash savings, if any, in U.S. federal, state, and local income tax or franchise tax that the Company 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 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 or, if either the Company or Parsley LLC so elects, cash, and (iii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The term of the TRA commenced on May 29, 2014, and continues until all such tax benefits have been utilized or expired, unless the Company exercises its right to terminate the TRA. If the Company elects to terminate the TRA early, it would be required to make an immediate payment equal to the present value of the hypothetical future tax benefits that could be paid under the TRA (based upon certain assumptions and deemed events set forth in the TRA). In addition, payments due under the TRA will be similarly accelerated following certain mergers or other changes of control.

The actual amount and timing of payments to be made under the TRA will depend on a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers and the portion of the Company's payments under the TRA constituting imputed interest. As of December 31, 2019, there have been no payments associated with the TRA.

As a result of the Tax Act's reduction in the corporate tax rate from 35% to 21% and the reduction in the valuation allowance the Company recorded in 2016, during the year ended December 31, 2017, the Company recorded a net decrease to the TRA liability of $35.8 million, which is comprised of a decrease of $55.9 million associated with the corporate rate reduction and an increase of $20.1 million related to the change in valuation allowance.

As of December 31, 2019 and December 31, 2018, the Company had recorded a TRA liability of $70.5 million and $68.1 million, respectively, for the estimated payments that will be made to the PE Unitholders who have exchanged shares, along with corresponding deferred tax assets, of $83.0 million and $80.1 million, respectively, as a result of the increase in tax basis arising from such exchanges and the decrease in tax basis as a result of the decrease in the future statutory tax rate.

NOTE 13. RELATED PARTY TRANSACTIONS

Well Operations

During the years ended December 31, 2019, 2018 and 2017, certain of the Company's directors, officers, their immediate family and entities affiliated or controlled by such parties ("Related Party Working Interest Owners") owned non-operated working interests in certain of the oil and natural gas properties that the Company operates. The revenues disbursed to such Related Party Working Interest Owners for the years ended December 31, 2019, 2018 and 2017 totaled $4.6 million, $1.7 million and $1.5 million, respectively.

As a result of this ownership, from time to time, the Company will be in a net receivable or net payable position with these individuals and entities. The Company does not consider any net receivables from these parties to be uncollectible.

Spraberry Production Services, LLC

As discussed in *Note 2—Summary of Significant Accounting Policies*, Parsley LLC, a subsidiary of the Company, indirectly owns a 42.5% interest in SPS. The Company accounts for this investment using the equity method. Using the equity method of accounting results in transactions between the Company and SPS and its subsidiaries being accounted for as related party transactions. During the years ended December 31, 2019, 2018 and 2017, the Company incurred charges totaling $6.9 million, $9.8 million and $10.2 million, respectively, for services performed by SPS for the Company's well operations and drilling activities.

Lone Star Well Service, LLC

The Company makes purchases of equipment used in its drilling operations from Lone Star Well Service, LLC ("Lone Star"), which is controlled by SPS. During the years ended December 31, 2018 and 2017, the Company incurred charges totaling $3.8 million and $6.5 million, respectively, for services performed by Lone Star for the Company's well operations and drilling activities. There were no such charges incurred for the year ended December 31, 2019.

Exchange Right

In accordance with the terms of the Parsley LLC Agreement, PE Unitholders (other than the Company) generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of the Class B common stock) for shares of Class A common stock at an exchange ratio of one share of Class A common stock for each PE Unit (and corresponding share of Class B common stock) exchanged (subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications) or, if the Company or Parsley LLC so elects, cash. As a PE Unitholder exchanges its PE Units, the Company's interest in Parsley LLC correspondingly increases. Refer to *Note 10—Equity—Noncontrolling Interests*.

During the year ended December 31, 2019, an executive officer of the Company elected to exchange 420,000 PE Units (and a corresponding number of shares of Class B common stock) for 420,000 shares of Class A common stock. The Company exercised its call right under the Parsley LLC Agreement and elected to issue Class A common stock to the exchanging PE Unitholder in satisfaction of such individual's election.

NOTE 14. COMMITMENTS AND CONTINGENCIES

Legal Matters

The Company is party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect, individually or in the aggregate, on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then-current status of the matters.

Environmental Obligations

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed as incurred. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2019 and 2018, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Operating and Finance Leases

The Company's estimated future minimum lease payments under long-term operating and finance lease agreements as of December 31, 2019 are associated with the Company's adoption of ASC 842 and relate to lease payment maturities. The Company's operating leases include drilling rigs, real estate, and other field and office equipment and the Company's finance leases include vehicles. See *Note 9—Leases* for additional information.

Derivative Obligations

The Company's future deferred premium payments related to derivative agreements as of December 31, 2019 was as follows (in thousands):

	Payments Due by Period						
	2020	2021	2022	2023	2024	Thereafter	Total
Derivative obligations	$ 58,855	$ —	$ —	$ —	$ —	$ —	$ 58,855

Transportation and Crude Oil Sales Agreements

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities.

The following table presents gross volume information, as of December 31, 2019, related to the Company's long-term transportation and crude oil sales agreements that specify the delivery of fixed and determinable quantities of crude oil:

	For the years ended December 31,						
	2020	2021	2022	2023	2024	Thereafter	Total
Oil (MMBbl)(1)	26.6	45.6	43.3	39.7	36.6	61.5	253.3
Dollar commitment(2) (in thousands)	$ 41,534	$ 79,530	$ 79,770	$ 75,112	$ 70,962	$ 126,666	$ 473,574

(1) This table is based on agreements that the Company has signed with third-party pipeline operators as of December 31, 2019. Of the total 253.3 MMBbls, 99.0 MMBbls are subject to the commencement of operations of third party-terminal and pipeline systems.

(2) These amounts equal the total deficiency fees payable, based on assumptions management considers reasonable, if the Company is unable to meet all of its contractual delivery commitments under its long-term transportation and crude oil sales agreements. Of the total $473.6 million, $204.1 million is associated with delivery commitments subject to the commencement of operations of third-party terminal and pipeline systems.

The Company expects to fulfill these delivery commitments with production from its existing proved developed and proved undeveloped reserves, which the Company regularly monitors to ensure sufficient availability. In addition, the Company monitors its current production, its anticipated future production and its future development plans, in each case factoring in production attributable to third-party working, royalty and overriding royalty interest owners, in order to meet its delivery commitments. If production volumes are not sufficient to meet these contractual delivery commitments, the Company may be subject to deficiency fees. However, in the event the Company is unable to meet any portion of such contractual delivery commitments, the Company may purchase commodities in the market at then-current market prices to satisfy the portion of such commitment that was not delivered, in which case such deficiency fees would not be payable.

NOTE 15. RESTRUCTURING AND OTHER TERMINATION COSTS

During the year ended December 31, 2019, the Company incurred restructuring and termination costs as part of the Company's continuing effort to reduce future general and administrative expenses, which included a reduction in employee count. These one-time, nonrecurring costs are reflected in *Restructuring and other termination costs* in the Company's consolidated statements of operations. The following table summarizes the Company's termination costs for the years ended December 31, 2019, 2018 and 2017, respectively (in thousands):

	Year ended December 31,		
	2019	2018	2017
Termination costs	$ 1,562	$ —	$ —
Total restructuring and other termination costs	$ 1,562	$ —	$ —

The Company has not recorded an additional liability for restructuring costs as no additional costs have been incurred.

NOTE 16. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

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

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

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

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. These assets and liabilities can include inventory, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, proved and unproved oil and natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable (*e.g.*, if there was a sustained decline in commodity prices or the productivity of the Company's wells). The Company reviews its oil and natural gas properties by field. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such asset.

Unproved oil and natural gas properties are assessed quarterly for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales, remaining lease terms and the expiration of all or a portion of such projects. The Company's periodic assessment also considers its ability to prioritize expenditures to drill leases and to make payments to extend the lease term as well as its ability to enter into exchange transactions that allow for higher concentrations of ownership and development. The Company recognizes leasehold abandonment expense for unproved properties at the time when the lease term has expired or sooner based on management's periodic assessments. During the years ended December 31, 2019, 2018 and 2017, the Company recognized leasehold abandonment and impairment expense of $99.2 million, $160.8 million and $32.9 million.

Other Property, Plant and Equipment. During the year ended December 31, 2019, the Company recognized an impairment of $2.6 million to reduce the carrying value of leasehold improvements that will no longer provide economic benefit after the cease-use date associated with certain office space. The impairment charges are included in *Other operating expense* in the Company's consolidated statements of operations. There were no such charges incurred during the years ended December 31, 2018 or 2017.

Materials and Supplies. During the years ended December 31, 2018 and 2017, the Company recognized impairments of $0.5 million and $1.1 million, respectively, primarily to reduce the carrying value of oil and gas drilling and repair items. There were no such impairments recognized during the year ended December 31, 2019. The Company estimates fair value of the inventory using significant Level 2 assumptions based on third-party price quotes for the asset in an active market. The impairment charges are included in *Other income (expense)* in the Company's consolidated statements of operations.

Proved Oil and Natural Gas Properties. During the years ended December 31, 2019 and 2018, the Company did not recognize impairment charges, as the carrying amount of the assets exceeds the undiscounted future cash flows of the assets.

The Company calculates the estimated fair values using a discounted future cash flow model. Management's assumptions associated with the calculation of discounted future cash flows include commodity prices based on NYMEX futures price strips (Level 1), as well as Level 3 assumptions including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes, and (v) estimated reserves.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves, and (iv) results of future drilling activities.

Financial Assets and Liabilities Measured at Fair Value

Commodity derivative contracts are marked-to-market each quarter and are thus stated at fair value in the Company's consolidated balance sheets and in *Note 4—Derivative Financial Instruments*. The Company adjusts the valuations from the valuation model for nonperformance risk and for counterparty risk. The fair values of the Company's commodity derivative instruments are classified as Level 2 measurements as they are calculated using industry standard models that utilize assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors. The following summarizes the fair value of the Company's derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated (in thousands):

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivative instruments(1)	$ —	$ 127,632	$ —	$ 127,632
Total assets	$ —	$ 127,632	$ —	$ 127,632
Liabilities:				
Commodity derivative instruments(1)	$ —	$ (158,522)	$ —	$ (158,522)
Total liabilities	$ —	$ (158,522)	$ —	$ (158,522)
Net liability	$ —	$ (30,890)	$ —	$ (30,890)

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivative instruments(1)	—	211,421	—	211,421
Total assets	—	211,421	—	211,421
Liabilities:				
Commodity derivative instruments(1)	—	(168,963)	—	(168,963)
Total liabilities	—	(168,963)	—	(168,963)
Net asset	$ —	$ 42,458	$ —	$ 42,458

(1) Includes deferred premiums to be settled upon expiration of the contract.

Financial Instruments Not Carried at Fair Value

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated balance sheets (in thousands):

	December 31, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt:				
6.250% senior unsecured notes due 2024	$ 400,000	417,028	$ 400,000	$ 394,144
5.375% senior unsecured notes due 2025	650,000	669,552	650,000	605,885
5.250% senior unsecured notes due 2025	450,000	464,697	450,000	424,980
5.625% senior unsecured notes due 2027	700,000	742,840	700,000	636,041
Revolving Credit Agreement	—	—	—	—

The fair values of the Notes were determined using the December 31, 2019 quoted market price, a Level 1 classification in the fair value hierarchy. The book value of the Revolving Credit Agreement approximates its fair value as the interest rate is variable. As of December 31, 2019, there were no indicators for change in the Company's market spread.

NOTE 17. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date these financial statements were issued. The Company determined there were no events, other than as described below, that required disclosure or recognition in these financial statements.

Jagged Peak Acquisition

On January 10, 2020, through a series of transactions, the Company acquired Jagged Peak Energy Inc., a Delaware corporation that previously traded on the New York Stock Exchange under the symbol "JAG" ("Jagged Peak"), pursuant to the Agreement and Plan of Merger, dated as of October 14, 2019, among the Company, Jackal Merger Sub, Inc., a Delaware corporation and wholly owned subsidiary of the Company, and Jagged Peak (the "Jagged Peak Acquisition").

As part of the Jagged Peak Acquisition, each eligible share of Jagged Peak common stock was automatically converted into the right to receive 0.447 shares of Class A common stock. As a result, the Company issued or distributed approximately 95.9 million shares of Class A common stock to former Jagged Peak stockholders upon the consummation of the Jagged Peak Acquisition.

In connection with the completion of the Jagged Peak Acquisition, Parsley LLC assumed Jagged Peak's guarantee of $500.0 million in aggregate principal amount of the 5.875% senior notes due 2026 (the "Jagged Peak 2026 Notes") of its subsidiary, Jagged Peak Energy LLC, a Delaware limited liability company ("Jagged Peak LLC"), and repaid in full all outstanding obligations under Jagged Peak's credit facility by drawing on the Revolving Credit Agreement. The Jagged Peak 2026 Notes are the senior unsecured obligations of Jagged Peak LLC, which became a wholly owned subsidiary of Parsley LLC upon the completion of the Jagged Peak Acquisition, and the other subsidiaries of Parsley LLC that are guarantors of the Jagged Peak 2026 Notes.

Acquisition costs of $7.4 million related to the Jagged Peak Acquisition are included in *Acquisition costs* in the Company's consolidated statements of operations for the year ended December 31, 2019. Jagged Peak's post-acquisition results of operations will be incorporated into the Company's interim condensed consolidated financial statements for the three months ended March 31, 2020.

Dividends

On January 23, 2020, the Company's board of directors declared a cash dividend of $0.05 per share of Class A common stock, and, in its capacity as the managing member of Parsley LLC, a corresponding distribution of $0.05 per PE Unit, payable on March 20, 2020 to holders of Class A common stock and PE Unitholders of record as of March 10, 2020. The portion of the

Parsley LLC distribution attributable to PE Units held by Parsley Energy, Inc. will be used to fund the quarterly dividend on issued and outstanding shares of Class A common stock. For additional information regarding Parsley LLC's distribution of cash for the payment of dividends, see *Note 10—Equity—Dividends*.

4.125% Senior Unsecured Notes Due 2028; Redemption of 2024 Notes

On February 11, 2020, Parsley LLC and Finance Corp. issued $400.0 million aggregate principal amount of 4.125% senior unsecured notes due 2028 (the "2028 Notes") in an offering that was exempt from registration under the Securities Act of 1933, as amended (the "2028 Notes Offering"). The 2028 Notes Offering resulted in net proceeds to the Company, after deducting estimated fees and expenses, of approximately $395.2 million. The Company intends to use such net proceeds and borrowings under the Revolving Credit Agreement to redeem all of the 2024 Notes on March 7, 2020 at a redemption price of 104.688%, plus accrued and unpaid interest to the redemption date, pursuant to the terms of the indenture relating to the 2024 Notes (the "2024 Notes Redemption"). In connection with the 2024 Notes Redemption, the Company will pay holders of the 2024 Notes approximately $425.5 million, which includes principal of $400.0 million, a prepayment premium on the extinguishment of debt of $18.8 million and accrued interest of approximately $6.7 million. Additionally, the Company will write off $4.8 million of debt issuance costs and $2.2 million of issue premium related to the 2024 Notes.

NOTE 18. SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

The Company has only one reportable operating segment, which is oil and natural gas development, exploration and production in the United States.

Capitalized Costs

	December 31,	
	2019	2018
	(in thousands)	
Oil and natural gas properties:		
Proved properties	$ 8,799,840	$ 6,659,444
Unproved properties	2,472,284	3,288,802
Total oil and natural gas properties	11,272,124	9,948,246
Less accumulated depreciation, depletion and amortization	(2,117,963)	(1,295,098)
Net oil and natural gas properties capitalized	$ 9,154,161	$ 8,653,148

Costs Incurred for Oil and Natural Gas Producing Activities

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Acquisition costs:			
Proved properties	$ 24,855	$ 17,310	$ 482,160
Unproved properties	27,165	119,662	2,893,434
Development costs	1,372,919	1,762,218	1,207,401
Total	$ 1,424,939	$ 1,899,190	$ 4,582,995

Results of Operations from Oil and Natural Gas Producing Activities

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

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Oil, natural gas and natural gas liquid sales(1)	$ 1,949,977	$ 1,814,747	$ 961,994
Lease operating expenses	(177,148)	(144,292)	(102,169)
Transportation and processing costs(1)	(41,198)	(32,573)	—
Production and ad valorem taxes	(124,961)	(108,342)	(59,641)
Depreciation, depletion and amortization	(775,849)	(569,691)	(340,778)
Accretion of asset retirement obligations	(1,465)	(1,422)	(971)
Total	$ 829,356	$ 958,427	$ 458,435

(1) Natural gas and NGLs sales and transportation and processing costs for the years ended December 31, 2019 and 2018 reflect adjustments associated with Parsley's adoption of ASC 606, effective January 1, 2018.

Reserve Quantity Information (Unaudited)

The following information represents estimates of the Company's proved reserves as of December 31, 2019, which have been prepared and presented in accordance with SEC rules. These rules require SEC reporting companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2019 was based on an unweighted average 12-month average U.S. Energy Information Administration WTI posted price per Bbl for oil and NGLs and a Waha spot natural gas price per Mcf for natural gas, adjusted for transportation, quality and basis differentials, as set forth in the following table:

	Year Ended December 31,		
	2019	2018	2017
Oil (per Bbl)	$ 53.97	$ 61.88	$ 49.17
Natural gas (per Mcf)	$ 0.71	$ 1.64	$ 2.53
Natural gas liquids (per Bbl)	$ 15.46	$ 28.05	$ 22.20

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement has limited and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are located in the United States in the Permian Basin of west Texas. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table and subsequent narrative disclosure provides a roll forward of the total proved reserves for the years ended December 31, 2019, 2018 and 2017, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Year Ended December 31, 2019			
	Crude Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	294,446	572,038	131,933	521,719
Extensions and discoveries	84,186	132,642	32,457	138,750
Revisions of previous estimates	(19,269)	60,128	(5,043)	(14,291)
Purchases of reserves in place	354	556	107	554
Divestures of reserves in place	(1,590)	(4,189)	(788)	(3,076)
Production	(31,664)	(51,933)	(11,002)	(51,322)
End of the year	326,463	709,242	147,664	592,334
Proved Developed Reserves:				
Beginning of the year	170,526	358,733	81,000	311,315
End of the year	206,849	472,160	96,202	381,744
Proved Undeveloped Reserves:				
Beginning of the year	123,920	213,305	50,933	210,404
End of the year	119,614	237,082	51,462	210,590

	Year Ended December 31, 2018			
	Crude Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	248,531	451,703	92,632	416,447
Extensions and discoveries	102,274	130,692	35,722	159,778
Revisions of previous estimates	(22,047)	48,992	16,164	2,283
Purchases of reserves in place	3,379	5,963	1,240	5,613
Divestures of reserves in place	(12,335)	(27,947)	(5,472)	(22,465)
Production	(25,356)	(37,365)	(8,353)	(39,937)
End of the year	294,446	572,038	131,933	521,719
Proved Developed Reserves:				
Beginning of the year	119,591	240,337	49,751	209,399
End of the year	170,526	358,733	81,000	311,315
Proved Undeveloped Reserves:				
Beginning of the year	128,940	211,366	42,881	207,048
End of the year	123,920	213,305	50,933	210,404

	Year Ended December 31, 2017			
	Crude Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	136,536	223,605	48,543	222,347
Extensions and discoveries	99,916	161,989	33,426	160,340
Revisions of previous estimates	(709)	32,342	4,522	9,205
Purchases of reserves in place	33,017	64,055	12,121	55,814
Divestures of reserves in place	(3,839)	(6,962)	(1,468)	(6,467)
Production	(16,390)	(23,326)	(4,512)	(24,792)
End of the year	248,531	451,703	92,632	416,447
Proved Developed Reserves:				
Beginning of the year	61,133	123,946	24,306	106,097
End of the year	119,591	240,337	49,751	209,399
Proved Undeveloped Reserves:				
Beginning of the year	75,403	99,659	24,237	116,250
End of the year	128,940	211,366	42,881	207,048

Extensions and Discoveries. For the years ended December 31, 2019, 2018 and 2017, extensions and discoveries contributed to the increase of 138,750 MBoe, 159,778 MBoe and 160,340 MBoe in the Company's proved reserves, respectively, and for each such year the increase is attributable to the Company's horizontal drilling program in the Midland Basin and the Delaware Basin.

Revisions of Previous Estimates. The Company made negative revisions in proved reserves of 14,291 MBoe and positive revisions of 2,283 MBoe and 9,205 MBoe for the years ended December 31, 2019, 2018 and 2017, respectively.

Negative revisions of previous estimates for 2019 were 14,291 MBoe. The main driver of these revisions was the reclassification of certain proved undeveloped ("PUD") reserves to unproved reserves, which resulted in a 23,686 MBoe downward revision to previous estimates related to the removal of reserves for PUD locations determined to be outside of the Company's five-year capital expenditure plan. Other drivers included changes in well performance, working interest and operating expenses, which together resulted in a positive revision of 11,498 MBoe. A negative revision of 2,103 MBoe was attributable to a price adjustment due to a decrease in pricing as calculated using SEC guidelines.

Positive revisions of previous estimates for 2018 were 2,283 MBoe. The main driver of these positive revisions was the adoption of ASC 606, which resulted in a positive revision of 11,434 MBoe. Other drivers included changes in well performance, working interest, operating expenses and pricing, which together resulted in a positive revision of 3,063 MBoe. The main driver of these downward revisions was the reclassification of certain PUD reserves to unproved reserves, which accounted for a 12,214 MBoe downward revision to previous estimates related to the removal of reserves for locations determined to be outside of the Company's five-year capital expenditure plan.

Positive revisions of previous estimates for 2017 were 9,205 MBoe. The main driver of these adjustments was better than expected performance for a total of 8,134 MBoe. Additionally, positive revisions of 2,752 MBoe and 3,044 MBoe were recorded due to increases in oil prices and production, respectively, as compared to the year ended December 31, 2016. These were offset by negative revisions of 4,725 MBoe associated with the reclassification of PUD reserves to unproved reserves.

Purchases of Reserves in Place. For the years ended December 31, 2019, 2018 and 2017, the Company added 554 MBoe, 5,613 MBoe and 55,814 MBoe of reserves, respectively, primarily as a result of the acquisition of developed and undeveloped acreage in the Midland and Delaware Basins. For the year ended December 31, 2019, the Company acquired 554 MBoe of proved reserves in the Midland Basin. For the year ended December 31, 2018, the Company acquired 5,550 MBoe of proved reserves in the Midland Basin and 63 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2017, the Company acquired 53,105 MBoe of proved reserves in the Midland Basin and 2,709 MBoe of proved reserves in the Delaware Basin.

Divestitures of Reserves in Place. As a result of divestitures of developed and undeveloped acreage in the Midland and Delaware Basins, the Company's reserves decreased by 3,076 MBoe, 22,465 MBoe and 6,467 MBoe during the years ended December 31, 2019, 2018 and 2017, respectively. For the year ended December 31, 2019, the Company divested 3,076 MBoe of proved reserves in the Midland Basin. For the year ended December 31, 2018, the Company divested 22,372 MBoe of proved reserves in the Midland Basin and 93 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2017, the Company divested 5,936 MBoe of proved reserves in the Midland Basin and 531 MBoe of proved reserves in the Delaware Basin.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of a property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2019, 2018 and 2017 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves is as follows:

	December 31,		
	2019	2018	2017
		(in thousands)	
Future cash inflows	$ 20,409,082	$ 22,861,246	$ 15,421,590
Future development costs	(2,280,552)	(2,459,587)	(2,181,447)
Future production costs	(6,240,997)	(5,944,022)	(4,536,530)
Future income tax expenses	(1,485,523)	(2,061,409)	(1,102,385)
Future net cash flows	10,402,010	12,396,228	7,601,228
10% discount to reflect timing of cash flows	(5,439,514)	(6,502,326)	(4,215,321)
Standardized measure of discounted future net cash flows	$ 4,962,496	$ 5,893,902	$ 3,385,907

In the foregoing determination of future cash inflows, sales prices used for oil, natural gas and NGLs for December 31, 2019, 2018 and 2017 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Standardized measure of discounted future net cash flows at the beginning of the year	$ 5,893,902	$ 3,385,907	$ 1,304,091
Sales of oil and natural gas, net of production costs	(1,606,669)	(1,561,190)	(800,553)
Purchase of minerals in place	7,411	76,478	489,910
Divestiture of minerals in place	(19,768)	(167,412)	(50,257)
Extensions and discoveries, net of future development costs	1,714,706	3,016,035	1,864,041
Previously estimated development costs incurred during the period	469,798	290,108	58,377
Net changes in prices and production costs	(2,205,679)	1,065,693	525,693
Changes in estimated future development costs	83,125	(177,118)	(150,028)
Revisions of previous quantity estimates	(146,203)	161,860	142,510
Accretion of discount	677,486	391,803	148,314
Net change in income taxes	187,697	(348,834)	(353,073)
Net changes in timing of production and other	(93,310)	(239,428)	206,882
Standardized measure of discounted future net cash flows at the end of the year	$ 4,962,496	$ 5,893,902	$ 3,385,907

NOTE 19. SUMMARY OF QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The Company's unaudited quarterly financial data for the years ended December 31, 2019 and 2018 is summarized as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2019				
Revenues	$ 427,671	$ 498,541	$ 510,151	$ 522,451
Operating income	$ 116,547	$ 180,837	$ 153,041	$ 86,845
Income tax benefit (expense)	$ 7,790	$ (32,625)	$ (34,953)	$ (1,649)
Net (loss) income	$ (28,003)	$ 134,994	$ 139,600	$ (36,173)
Net (loss) income attributable to noncontrolling interests	$ (3,939)	$ 19,059	$ 19,890	$ 196
Net (loss) income attributable to Parsley Energy, Inc. stockholders	$ (24,064)	$ 115,935	$ 119,710	$ (36,369)
Net (loss) income per common share:				
Basic	$ (0.09)	$ 0.41	$ 0.43	$ (0.13)
Diluted	$ (0.09)	$ 0.41	$ 0.43	$ (0.13)
2018				
Revenues	$ 392,741	$ 467,788	$ 511,022	$ 454,880
Operating income	$ 169,207	$ 215,505	$ 220,992	$ 22,171
Income tax expense	$ (23,325)	$ (33,243)	$ (32,454)	$ (16,453)
Net income	$ 105,463	$ 140,958	$ 134,149	$ 65,399
Net income attributable to noncontrolling interests	$ 22,573	$ 21,803	$ 20,840	$ 11,626
Net income attributable to Parsley Energy, Inc. stockholders	$ 82,890	$ 119,155	$ 113,309	$ 53,773
Net income per common share:				
Basic	$ 0.32	$ 0.44	$ 0.41	$ 0.19
Diluted	$ 0.32	$ 0.44	$ 0.41	$ 0.19

FREE CASH FLOW (OUTSPEND) RECONCILIATION

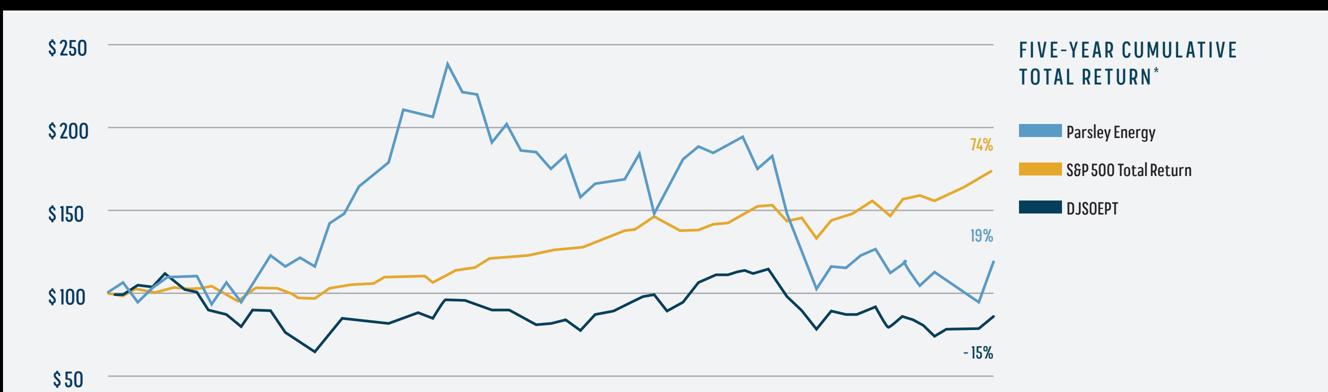
(UNAUDITED, IN THOUSANDS)

	Six Months Ended June 30, 2019	Six Months Ended December 31, 2019	Twelve Months Ended December 31, 2019
Net cash provided by operating activities	$ 615,882	$ 670,397	$ 1,286,279
Net change in operating assets and liabilities, net of acquisitions	(15,556)	(875)	(16,431)
Transaction expenses related to the acquisition of Jagged Peak Energy Inc.	—	7,413	7,413
Total discretionary cash flow	**$ 600,326**	**$ 676,935**	**$ 1,277,261**
Development of oil and natural gas properties	$ (737,194)	$ (635,901)	$ (1,373,095)
(Additions) reductions to oil and natural gas properties - change in capital accruals	(41,124)	41,300	176
Total accrual-based development capital expenditures	$ (778,318)	$ (594,601)	$ (1,372,919)
Free cash flow (outspend)	**$ (177,992)**	**$ 82,334**	**$ (95,658)**

CASH RETURN ON CAPITAL INVESTED (CROCI) RECONCILIATION

(UNAUDITED, IN THOUSANDS)

	2018	2019
Net cash provided by operating activities	$	$ 1,286,279
After-tax interest expense (at 21% corporate tax rate)		105,576
Numerator		**$ 1,391,855**
Total property, plant, equipment (net)	$ 8,823,887	$ 9,324,467
Accumulated depreciation, depletion, amortization, and impairment	(1,295,098)	(2,117,963)
Total property, plant, equipment (gross)	**$ 10,118,985**	**$ 11,442,430**
Non-cash working capital	**$ (310,416)**	**$ (325,902)**
Assets		
Accounts receivable - joint interest owners and other	39,564	48,785
Accounts receivable - oil, natural gas, and NGLs	136,209	192,216
Accounts receivable - related parties	94	183
Other current assets	10,332	8,818
Liabilities		
Accounts payable and accrued expenses	364,803	416,346
Revenue and severance taxes payable	127,265	154,556
Other current liabilities	4,547	5,002
Denominator		**$ 10,462,549**
2019 CROCI		**13.3%**



* Assumes an investment of $100 on December 31, 2014 in our Class A common stock, the Dow Jones U.S. Select Oil Exploration & Production Total Return Index, and the S&P 500 Total Return Index, including the reinvestment of dividends, if any. Fiscal year ending December 31.

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