Jagged Peak
ENERGY

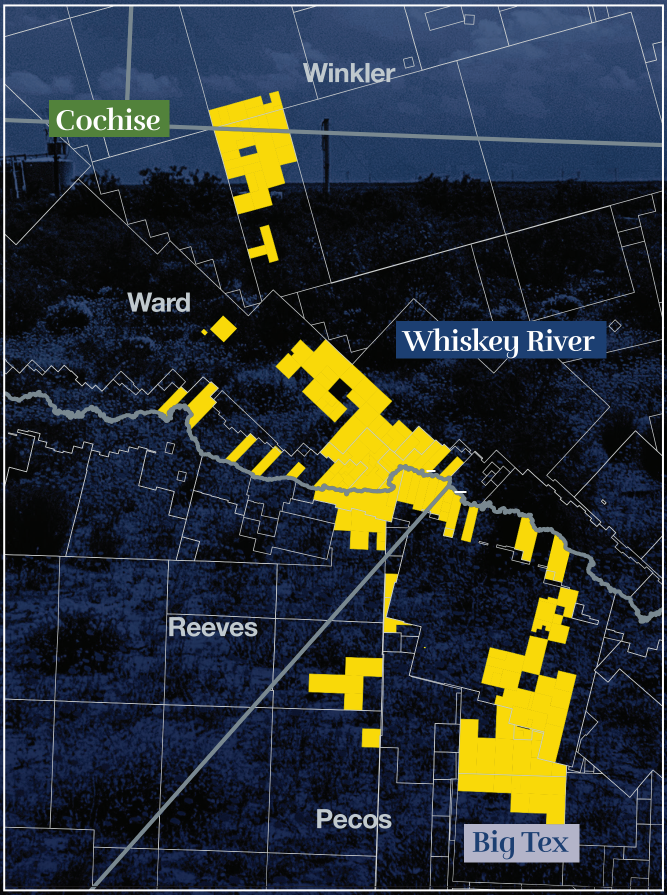
2017 Annual Report

About Jagged Peak Energy

Jagged Peak is a pure play, growth-oriented, independent oil and natural gas company focused on the development of its top-tier acreage position in the heart of the Delaware basin, a sub-basin of the Permian Basin in West Texas. With approximately 75,000 net acres in the adjacent counties of Winkler, Ward, Reeves and Pecos, Jagged Peak has identified more than 2,000 drilling locations targeting significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. By using advanced drilling and completion techniques and leveraging our management team's extensive experience and technical expertise, we are positioned to execute on maximizing returns to shareholders.

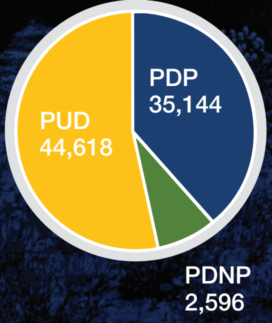
Operations

Jagged Peak's acreage is located on large, contiguous blocks in West Texas with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. As year-end 2017, Jagged Peak had total proved reserves of 82.4 MMboe and operated approximately 97% of its net acreage. The contiguous acreage position and higher operational control enables the drilling of long laterals, resulting in significant drilling efficiencies that enhance the economic development of the Company's acreage position. The Jagged Peak team is dedicated to the development of a multidecade inventory of horizontal targets with an ongoing focus on reducing drilling times, optimizing completions and reducing costs.

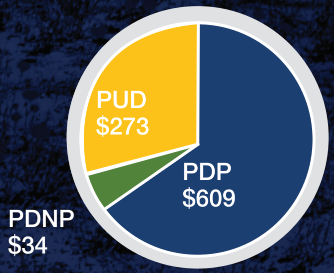


Increased total proved reserves in 2017 from 37.7 MMBoe to 82.4 MMBoe

Reserves by Category
(MBOE)



Value of Reserves by Type
($916MM Total PV10)



Letter *to our* Shareholders

Started in 2013 with a singular focus of building a world class asset base, our employees successfully established a top-tier acreage position and developed processes to maximize value for decades to come. With a successful initial public offering (IPO) of shares on January 26, 2017, Jagged Peak Energy established itself in the public markets as a leading Southern Delaware Basin pure-play operator. In our short time as a public company, our team has accomplished great things.

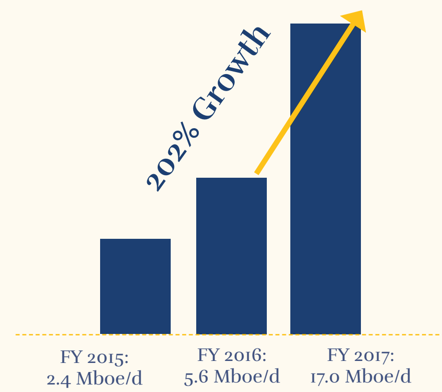
We added 14,000 acres since filing our S-1 in December of 2016, bringing our total net acreage to over 75,000, and completing 46 wells. Over the course of 2017, we increased production 202% and exited the year at 24,037 barrels of oil per day by year-end. As quickly as we have grown in 2017, there remains tremendous potential for further growth moving forward.

> *Jagged Peak's asset base is characterized by high quality rock, high oil cuts and efficient development through long lateral drilling programs.*

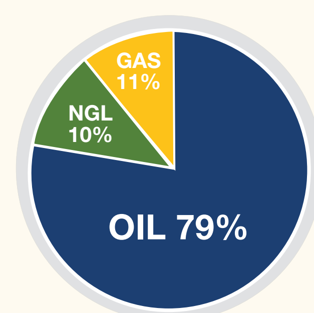
In 2017, we generated a reserve replacement ratio of over 800% and ended the year with total proved oil and gas reserves of 82.4 MMBoe an increase of 118% compared to proved reserves at the end of 2016. Importantly, our reserves base remains one of the oiliest in the basin with 79% of our total reserves volumes being oil and 10% made up of NGL.

Jagged Peak remains an industry cost leader with lease operating expense (LOE) at $2.88 per barrel of oil equivalent, down 21% from 2016, and total cash operating expenses down 17%. Our leading cost structure and oil content support a robust cash EBITDAX margin of $32.81 per barrel of oil equivalent.

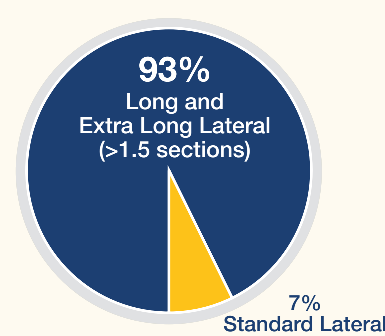
Production Growth



High Oil Cut - Reserves



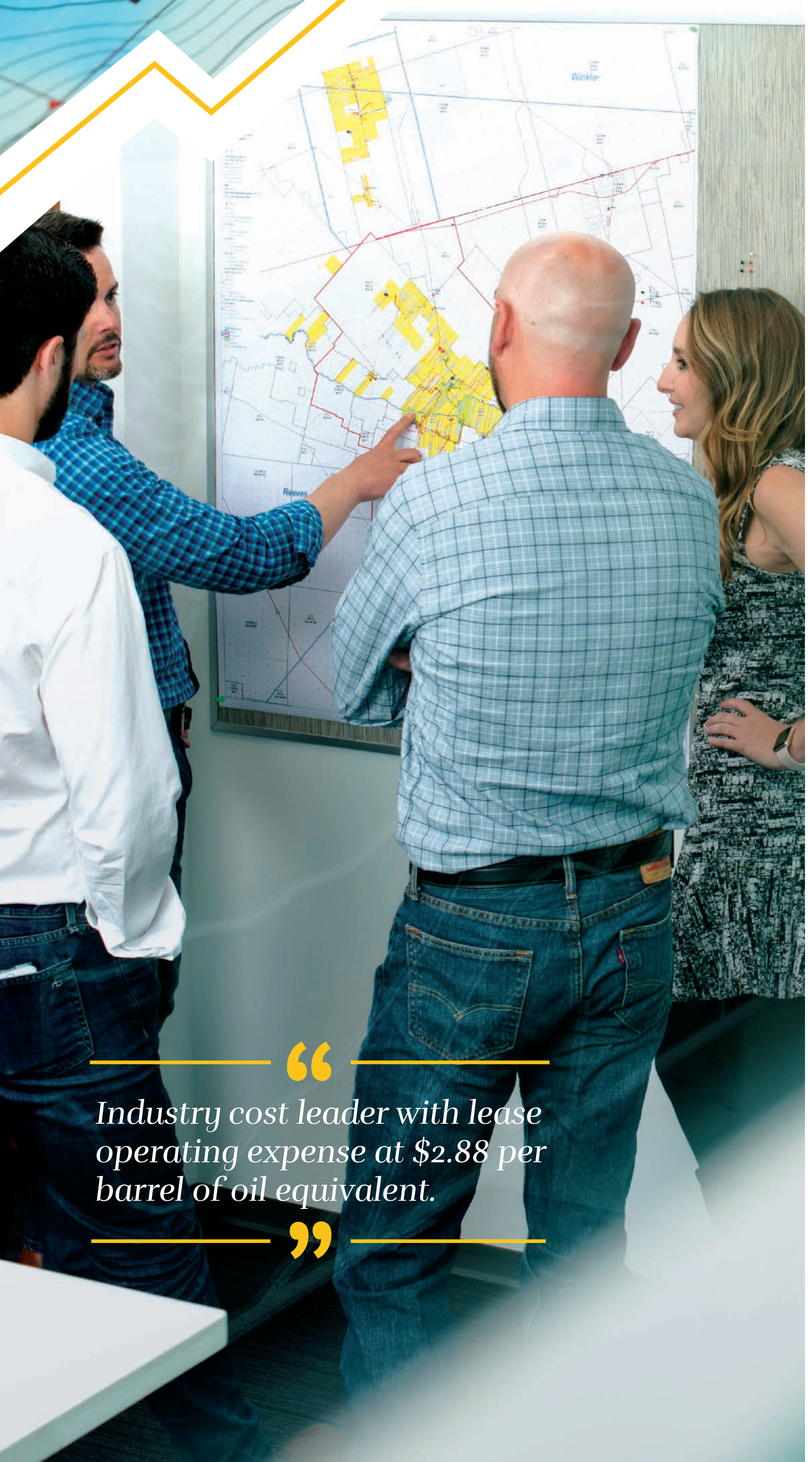
Extensive Drilling Inventory



More Than

2,000+

Identified Potential Drilling Locations



Industry cost leader with lease operating expense at $2.88 per barrel of oil equivalent.

Advantaged Acreage in a Premium Basin

Our position in the Southern Delaware Basin is unique. Thanks to our contiguous land position, we're able to drill some of the longest wells in the basin, with our average lateral measuring 7,257 feet during 2017. This contiguous acreage also benefits from being in the peak oil generation window where we produce high-quality oil and we benefit from favorably deep and over-pressured rock.

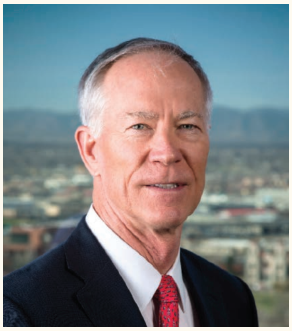
Our lowest cost method of growing inventory is to establish more resources on our exiting acreage. We continue to successfully test new landing zones and targets to delineate additional resources, add reserves and gather information for full field development. During 2017, we successfully drilled wells targeting three new zones: the 2nd Bone Spring, Wolfcamp C and the Woodford Shale. This success highlights our team's continued work towards de-risking the very thick oil column across our leasehold position, and we are encouraged with the initial results of these wells. With the inclusion of our first 3rd Bone Spring well announced in December, Jagged Peak is now producing from eight distinct zones in the most prolific play in the country.

We continue to develop our eastern acreage and the Big Tex area to further expand the footprint of our inventory, and with further down-spacing success, we are realizing even greater upside from the benches we already know work well. This combination of a large and contiguous footprint with a depth of targets and increasingly optimized completions provided the springboard for our impressive growth throughout 2017. Currently, we have over 2,090 identified potential drilling locations, and with the upside potential of more benches and tighter spacing, we believe that number will increase going forward.

I am proud of all that our team has accomplished this year, and 2017 only marks the beginning of unlocking the full value of Jagged Peak. What we have accomplished at Jagged Peak is the most satisfying part of my 37-year career in the industry. As I depart from my role as CEO, I do it with confidence in the organization, confidence in the assets and confidence in the leadership of Jim Kleckner, my successor. In Jim, I believe we have the experience to take the company to the next level of performance. I want to thank the organization that has been my support, as colleagues, friends and family.

Sincerely,

Joe Jaggers



A Message from
Jim Kleckner

A Foundation for the Future

On behalf of the Board of Directors, I want to thank Joe for his leadership and vision in building Jagged Peak Energy into a sustainable company with world class assets. With growth and execution comes the opportunity to continue adding to an already exceptional team. In 2017, Jagged Peak more than doubled its size with the very best minds and experts the oil and gas sector has to offer. This growth continues as we build on a culture centered around technical leadership and operational excellence that will provide the foundation for our company to remain a leader for many years to come.

In 2018, we plan to build on this success by increasing organizational capabilities and implementing the following strategic initiatives:

- Increase technical understanding of the reservoir system by integrating 3D seismic and other data gathering initiatives
- Demonstrate capital discipline and strict cost control by drilling the most economic well locations
- Maintain peer-leading cost structure by building out operated water infrastructure that allows for cost-efficient water transportation and disposal
- Generate best-in-class operation execution by reducing spud-to-spud cycle times, drilling longer laterals and optimizing completions
- Preserve the balance sheet and maintain a conservative leverage profile
- Continue an active hedging program to protect cash flow stability

I would like to take this opportunity to thank our employees and shareholders for all of their effort and support. The future for our company is bright, and I am excited to build on our foundation of low costs, high quality assets and operational excellence.

Sincerely,

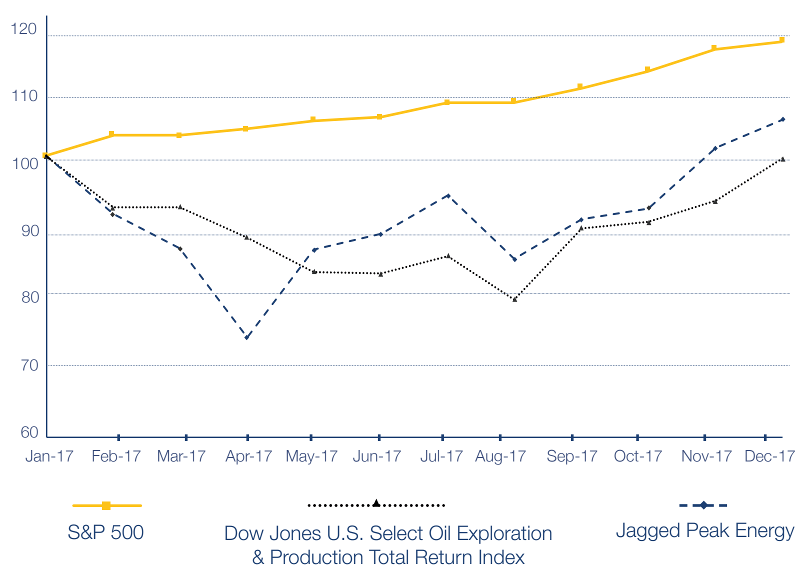
Jim Kleckner

Comparative Stock Performance Graph

The information contained in this Comparative Stock Performance Graph section shall not be deemed to be "soliciting material" or "filed" or incorporated by reference in future filings with the SEC, or subject to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act of 1933, as amended, or the Exchange Act.

The graph below compares the cumulative total shareholder return on our common stock, the cumulative total return on the S&P 500 Index, and the Dow Jones U.S. Select Oil Exploration & Production Total Return Index, since January 26, 2017, the day our common stock was listed on the New York Stock Exchange (the "NYSE"). The graph assumes $100 was invested on January 26, 2017, the first day our stock listed on the NYSE, in our common stock, the S&P 500 Index, and the Dow Jones U.S. Select Oil Exploration & Production Total Return Index. The cumulative total return assumes the reinvestment of all dividends.

Comparison of Cumulative Total Return Among Jagged Peak Energy, the S&P 500, and the Dow Jones U.S. Select Oil Exploration & Production Total Return Index



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

Form 10-K

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

For the fiscal year ended December 31, 2017

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-37995

Jagged Peak Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	**81-3943703**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)

1401 Lawrence St., Suite 1800 Denver, Colorado 80202
(Address, including zip code, of registrant's principal executive offices)

(720) 215-3700
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 ☒ (Do not check if a smaller reporting company)	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 ☒

The aggregate market value of common stock held by non-affiliates as of June 30, 2017, the last business day of the registrant's most recently completed second quarter, was approximately $621,362,774. This amount is based on the closing price of the registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant and holders of 10% or more of the outstanding common stock of the registrant have been excluded from the calculation of this amount because such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The registrant had 213,126,310 shares of common stock outstanding at March 9, 2018.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's definitive proxy statement for the 2018 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2017, are incorporated by reference into Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) same drive mechanism. For a complete definition of analogous reservoir, refer to the SEC's Regulation S-X, Rule 4-10(a)(2).

Basin. A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

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

Completion. The installation of permanent equipment for production of oil, natural gas or NGLs or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

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.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. For a complete definition of development costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(7).

Development project. The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities may constitute a development project.

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.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry well. A well found to be incapable of producing hydrocarbons in commercial quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

Economically producible. The term economically producible, as it relates to a resource, means a resource which 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).

Estimated ultimate recovery or EUR. The sum of reserves remaining as of a given date and cumulative production as of that date.

Ethane rejection. Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being extracted and sold as a liquid after fractionation. When ethane is left in the gas stream, the Btu content of the residue gas sold is higher and marginally increases the realized price of residue gas; conversely, the volumes of NGLs sold are lower and the average realized price for NGLs sold is higher, as ethane is typically the lowest priced component of NGLs sold. Producers generally elect to "reject" ethane when the price received for the ethane in the gas stream is greater than the net price received for the ethane being sold as a liquid after fractionation.

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. For a complete definition of exploration costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(12).

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Held by production. Acreage covered by a mineral lease that perpetuates a lessee's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

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

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBbl. One million barrels of crude oil, condensate or NGLs.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcf/d. One MMcf per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be. For example, an owner who has 50% interest in 100 acres owns 50 net acres. Likewise, an owner who has a 50% working interest in a well has a 0.50 net well.

Net production. Production that is owned by us less royalties and production due to others.

Net revenue interest. A working interest owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests, which are owned by other parties.

NGL(s). Natural gas liquid(s). Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

NYMEX. The New York Mercantile Exchange.

Operator. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

Productive well. An exploratory or development well that is not a dry well.

Proration unit. A unit that can be effectively and efficiently drained by one well, as allocated by a governmental agency having regulatory jurisdiction.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved developed reserves. Reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved properties. Properties with proved reserves.

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

Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

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

Recompletion. The completion for production of an existing wellbore in another formation, or other zones within the same formation, from which the well has been previously completed.

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

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 projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of an interest in the leasehold in connection with a transfer to a subsequent owner.

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. For example, if wells on a 640-acre section are drilled evenly such that each well is assigned to drain 40 acres, each of the resulting 16 wells would be spaced on 40 acres per well.

Spot market price. The cash market price for oil, natural gas, or NGLs without reduction for expected quality, transportation and demand adjustments.

Spud. Commenced drilling operations on an identified location.

Stacked hydrocarbon-bearing formations. Vertically layered geologic zones that exist at differing underground depths and are capable of producing oil, natural gas and NGLs. The existence of stacked-hydrocarbon bearing formations enables the development of multiple hydrocarbon bearing zones from a common surface area.

Standardized measure. Discounted future net cash flows estimated by applying the average price for the last 12 months to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

Success rate. The percentage of wells drilled which produce hydrocarbons in commercial quantities.

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

Unit, drilling unit or spacing unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation in coordination with the separate property interests. Also, the area covered by a unitization agreement.

Unproved properties. Lease acreage with no proved reserves.

Wellbore. The hole drilled by the bit that is equipped for oil, natural gas and NGLs production on a completed well. Also called well or borehole.

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

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

WTI. West Texas Intermediate. A market index price for oil that is widely quoted by financial markets.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Form 10-K includes "forward-looking statements." All statements, other than statements of historical fact included in or incorporated by reference into this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under "Item 1A. Risk Factors" in this Annual Report on Form 10-K.

Forward-looking statements include statements about:

- our business strategy;
- our reserves;
- our drilling prospects, inventories, projects and programs;
- our intention to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our drilling program and our expectation that our cash flows from operating activities, access to capital markets and availability under our credit facility will be sufficient to fund our working capital needs;
- our expected pricing and realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our future drilling plans, including the number of wells anticipated to be spud in 2018 and wells anticipated to be completed and brought online in 2018, and anticipated well economics;
- our future drilling locations and zones and growth opportunities;
- our expected use of longer laterals, pad drilling, shared facilities and zipper fracs to improve our well economics;
- government regulations and our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- our hedging strategy and results;
- general economic conditions;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this annual report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the 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" in this Annual Report on Form 10-K.

Reserve engineering is a process of estimating underground accumulations of hydrocarbons 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 impact our strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10-K.

Emerging Growth Company Status

We are an “emerging growth company” as defined in the Jumpstart Our Business Startups Act, or the “JOBS Act.” For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to:

- provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the “PCAOB,” requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”); or
- obtain shareholder approval of any golden parachute payments not previously approved.

We will cease to be an “emerging growth company” upon the earliest of:

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a “large accelerated filer” (the fiscal year end on which the total market value of our common equity securities held by non-affiliates is $700 million or more measured as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the “Securities Act,” for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Jagged Peak Energy Inc., a Delaware corporation, is an independent oil and natural gas exploration and production company with operations in the southern Delaware Basin; the Delaware Basin is a sub-basin of the Permian Basin of West Texas. Throughout this Form 10-K, references to "Jagged Peak," the "Company," "we," "us" and "our" refer to Jagged Peak Energy Inc. and its subsidiaries, after the initial public offering of Jagged Peak (the "IPO") and, prior to the IPO, to Jagged Peak Energy LLC ("JPE LLC").

JPE LLC, a Delaware limited liability company, was formed in April 2013 by an affiliate of Quantum Energy Partners ("Quantum") and certain members of our management team. Jagged Peak was formed and incorporated in the state of Delaware in September 2016. In January 2017, pursuant to a corporate reorganization completed in connection with the IPO, JPE LLC became a wholly-owned subsidiary of Jagged Peak (the "corporate reorganization").

Business Overview

We are an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the southern Delaware Basin. We are focused on increasing stockholder value by (i) growing production and reserves through the development of our multi-year inventory, (ii) expanding and improving the resource potential of our existing acreage position, (iii) growing our acreage position through acquisitions and leasing efforts and (iv) balancing the long-term development of our assets with a focus on generating attractive corporate-level returns.

The following table summarizes information regarding our operations as of December 31, 2017:

Area	Estimated Proved Reserves (MBoe)	% Oil	Total Net Acres	Gross Operated Potential Drilling Locations	Avg Lateral Length (feet)	2017 Avg Daily Production (Boe/d)
Southern Delaware Basin	82,358	79%	75,200	2,083	9,094	16,974

During 2017, our average daily production of 16,974 Boe/d averaged 80% oil, 10% NGLs and 10% natural gas.

Our Properties and Operations

Our acreage is located on large, contiguous blocks in the adjacent West Texas counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. As of December 31, 2017, we operated approximately 97% of our net acreage and held an average 86% working interest in approximately 87,600 gross (75,200 net) acres. This operational control gives us flexibility in development strategy and pace. Our development drilling plan is comprised exclusively of horizontal drilling with an ongoing focus on reducing drilling times, optimizing completions and reducing costs. We expect that further optimization in the field, which may include increased drilling of longer laterals, pad drilling, shared facilities and zipper fracs (i.e. fracturing adjacent wells in parallel, with one or more wells holding frac pressure while the adjacent well is fractured) will continue to improve our well economics.

We divide our current area of operation within the southern Delaware Basin into three distinct project areas: Cochise, Whiskey River and Big Tex. The Cochise project area lies in the northern part of our acreage position and straddles Ward and Winkler Counties. Whiskey River is in the central part of our overall leasehold position and primarily lies just west of the junction between Ward, Reeves and Pecos Counties in Texas. The Whiskey River project area also includes a leasehold block informally named County Line, which is in northern Pecos County, just south of the majority of the Whiskey River leasehold. The Big Tex project area is our southernmost leasehold position and lies in northern Pecos County.

The following table summarizes our approximate acreage by project area as of December 31, 2017:

	Acreage	
Project Area:	**Gross**	**Net**
Cochise	13,300	12,900
Whiskey River	42,200	36,000
Big Tex	32,100	26,300
Total	87,600	75,200

Through December 31, 2017, we have drilled, completed and are producing from 67 gross (64.5 net) wells operated horizontal wells in eight distinct targets: 2nd Bone Spring, 3rd Bone Spring, Upper Wolfcamp A, Lower Wolfcamp A, Upper Wolfcamp B, Lower Wolfcamp B, Wolfcamp C and Woodford. Other operators have maintained active drilling and completion operations on acreage offsetting our acreage position. We continue to monitor this offset activity, especially with respect to downspacing pilots, and will adjust our future development plans to allow for the optimal development of our acreage position. We also believe significant additional development opportunities exist on portions of our acreage in the Brushy Canyon, Avalon Shale, 1st Bone Spring and Pennsylvanian aged formations.

Our contiguous acreage position enables the drilling of long laterals, resulting in significant drilling efficiencies that enhance the economic development of our acreage position. Of our 2,083 gross horizontal drilling locations as of December 31, 2017, 87% are classified as long or extra-long. We consider laterals of 5,640 feet and lower as standard length, laterals between 5,640 feet and 8,000 feet to be long, and laterals greater than 8,000 feet to be extra-long. The ability to drill long-lateral wells improves our returns by (i) increasing our EUR per well, (ii) allowing us to contact more reservoir rock with fewer vertical wellbores (thus reducing drilling and completion costs on a per unit basis) and (iii) allowing us to hold by production more acreage per horizontal well drilled. Additionally, the contiguous nature of our acreage provides economies of scale by allowing us to better share our infrastructure among wells across our acreage position.

During 2017, we operated an average of approximately six horizontal rigs, compared to an average of approximately two during 2016. During this same period, our average daily production has grown from 4,102 Boe/d in the first quarter of 2016 to 24,037 Boe/d in the fourth quarter of 2017. During 2017, we completed, or participated in completing, and began production on 51 gross (46.1 net) wells, of which we operated 46 gross (44.3 net) wells. As of December 31, 2017, we have 100 gross (94.0 net) producing wells. At year end, we were in the process of drilling nine gross (8.6 net) wells and had seven gross (6.4 net) wells waiting on completion, including three gross (2.8 net) wells that were in process of being completed. At December 31, 2017, we were operating six horizontal rigs.

Proved Reserves

Evaluation and Audit of Proved Reserves. Our proved reserve estimates as of December 31, 2017, 2016 and 2015, were prepared by Ryder Scott Company, LP ("Ryder Scott"), our independent petroleum engineers. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of Ryder Scott's proved reserve report as of December 31, 2017 is included as an exhibit to this Form 10-K.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to Ryder Scott for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. James T. Jaggers, our Reservoir Engineering Manager, is primarily responsible for overseeing the preparation of all of our reserve estimates. James T. Jaggers is a reservoir engineer with over 12 years of reservoir and operations experience, and has been licensed by the Texas Board of Professional Engineers since 2009.

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

- review and verification of historical operating and production data, which data is based on actual production as reported by us;
- review of reserve estimates by our Reservoir Engineering Manager or under his direct supervision;
- review by our Vice President, Development Planning and Geoscience of all of our reported proved reserves, including the review of all significant reserve changes and all new PUDs additions;
- direct reporting responsibilities by our Vice President, Development Planning and Geoscience to our Executive Vice President and Chief Operating Officer; and
- verification of property ownership by our land department.

Estimation of Proved Reserves. Under rules set forth by the United States Securities and Exchange Commission (the "SEC"), 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2017, 2016 and 2015 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the SEC's regulations. 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 three broad categories or methods: (i) performance-based methods; (ii) volumetric-based methods; and (iii) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Proved producing reserves for our properties were estimated by performance methods for the majority of properties. Certain new producing properties with inadequate historical production data were forecast using analogy or a combination of methods. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using analogy methods.

To estimate economically recoverable proved oil and natural gas reserves and related future net cash flows, Ryder Scott considered many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

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 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. 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, available seismic data and historical well cost and operating expense data.

Summary of Reserves. The following table presents our estimated net proved reserves as of December 31, 2017, 2016 and 2015, based on the proved reserve report as of such dates by Ryder Scott, prepared in accordance with the rules and regulations of the SEC. All of our proved reserves are located in the United States.

	At December 31,		
	2017	2016	2015
Proved Developed Reserves:			
Oil (MBbls)	29,325	11,916	4,848
Natural gas (MMcf)	25,496	6,566	2,547
NGLs (MBbls)	4,166	1,491	621
Total equivalent proved developed reserves (MBoe)	37,739	14,501	5,894
Proved Undeveloped Reserves:			
Oil (MBbls)	35,732	18,490	5,645
Natural gas (MMcf)	27,758	12,953	3,610
NGLs (MBbls)	4,260	2,545	870
Total equivalent proved undeveloped reserves (MBoe)	44,619	23,194	7,117
Total Proved Reserves:			
Oil (MBbls)	65,057	30,406	10,493
Natural gas (MMcf)	53,254	19,519	6,157
NGLs (MBbls)	8,426	4,036	1,491
Total equivalent proved reserves (MBoe)	82,358	37,695	13,011

The above reserve estimates were determined using the trailing 12-month index prices in accordance with SEC guidance. These prices were adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The following table summarizes the average adjusted product prices for 2017, 2016 and 2015:

	At December 31,		
	2017	2016	2015
Oil price per Bbl	$ 48.26	$ 39.33	$ 46.26
Natural gas price per Mcf	$ 2.59	$ 2.22	$ 2.36
NGL price per Bbl	$ 26.69	$ 15.48	$ 16.49

Estimated proved reserves at December 31, 2017 were 82.4 MMBoe, compared to 37.7 MMBoe at December 31, 2016, and 13.0 MMBoe at December 31, 2015. The increases in proved reserves during 2017 were primarily related to increased drilling activities. During 2017, we drilled and completed, or participated in drilling and completing, 51 gross (46.1 net) wells and added 49 gross (45.0 net) PUD locations. This activity resulted in a combined increase of 51.8 MMBoe through extensions and discoveries. Over this time period, we also had approximately 1.0 MMBoe of downward revisions to prior estimates due primarily to 2.2 MMBoe of negative revisions related to higher operating costs, partially offset by positive revisions due to pricing (0.6 MMBoe) and technical revisions (0.6 MMBoe).

Proved Undeveloped Reserves

Proved undeveloped reserves ("PUDs") are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated PUDs during 2017:

	(in MBoe)
Proved undeveloped reserves at December 31, 2016	23,194
Converted to developed	(10,386)
Additions	31,405
Net revisions	406
Proved undeveloped reserves at December 31, 2017	44,619

We saw a net increase of 21.4 MMBoe in PUD reserves during the year ended December 31, 2017. The increase in PUD reserves included 49 gross (45.0 net) new PUD locations, totaling 31.4 MMBoe, that were added as a result of offset drilling. Development drilling resulted in the reclassification of 10.4 MMBoe to proved developed reserves.

The 10.4 MMBoe of PUDs converted to proved developed reserves in 2017 were converted at a total capital cost of approximately $151.4 million. Our estimated total capital costs to develop our remaining proved undeveloped reserves at December 31, 2017 are approximately $579 million.

As of December 31, 2017, all our PUD drilling locations are scheduled to be drilled within five years of their initial booking. Additionally, as of December 31, 2017, 2.6 MMBoe of our proved developed reserves were classified as proved developed non-producing, and related to six gross (3.5 net) wells that began producing in the first quarter of 2018.

For further information about our reserves, refer to "Supplemental Oil and Natural Gas Disclosures (Unaudited)" which is included as supplemental information to the financial statements in this Form 10-K.

Production, Production Prices and Production Costs

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

	Year Ended December 31,		
	2017	2016	2015
Production:			
Oil (MBbls)	4,979	1,702	718
Natural gas (MMcf)	3,601	953	404
NGLs (MBbls)	617	194	89
Total (MBoe)	6,196	2,054	874
Average sales price:			
Oil (per Bbl)	$ 48.56	$ 41.18	$ 43.92
Natural gas (per Mcf)	$ 2.52	$ 2.32	$ 2.35
NGLs (per Bbl)	$ 25.25	$ 15.81	$ 14.93
Total (per Boe)	$ 43.00	$ 36.68	$ 38.69
Average sales price after impact of cash-settled derivatives:			
Oil (per Bbl)	$ 48.04	$ 39.84	$ 52.19
Natural gas (per Mcf)	$ 2.52	$ 2.32	$ 2.35
NGLs (per Bbl)	$ 25.25	$ 15.81	$ 14.93
Total (per Boe)	$ 42.58	$ 35.57	$ 45.48
Operating expenses per Boe:			
Lease operating expenses	$ 2.88	$ 3.65	$ 3.62
Gathering and transportation expenses	$ 0.71	$ 0.51	$ 0.20
Production and ad valorem taxes	$ 2.60	$ 2.12	$ 2.57

Developed and Undeveloped Acreage

Developed acreage consists of acres spaced or assigned to productive wells and does not include all undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Jagged Peak as of December 31, 2017. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

	Developed		Undeveloped		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Southern Delaware Basin	19,800	17,200	67,800	58,000	87,600	75,200

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 or held by continuous development operations, in which event the lease will remain in effect until the cessation of production. Substantially all of the leases governing our acreage have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 120 to 180 days after the completion of the last well drilled on such lease, without the requirement of a lease extension payment. Thereafter, the lease is held with additional development every 120 to 180 days until the entire lease is held by production. None of our horizontal drilling locations associated with proved undeveloped reserves are scheduled for drilling outside of a lease term that is not accounted for with a continuous development schedule or primary term. As of December 31, 2017, approximately 52% of our total net acreage was held by production or continuous development operations.

The following table sets forth the number of net undeveloped acres as of December 31, 2017 that will expire unless production is established within the spacing units covering the acreage prior to the expiration dates, or unless such acreage is extended or renewed.

Area	2018	2019	2020	Thereafter
Southern Delaware Basin	7,100	12,900	13,200	1,400

Drilling Results

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

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive(1)	1.0	1.0	—	—	—	—
Dry(2)	—	—	—	—	1.0	1.0
Total Exploratory	1.0	1.0	—	—	1.0	1.0
Development Wells						
Productive(1)	50.0	45.1	11.0	10.9	7.0	6.4
Dry(3)	—	—	—	—	—	—
Total Development	50.0	45.1	11.0	10.9	7.0	6.4
Total Wells						
Productive(1)	51.0	46.1	11.0	10.9	7.0	6.4
Dry(2)	—	—	—	—	1.0	1.0
Total	51.0	46.1	11.0	10.9	8.0	7.4

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

(2) Relates to a vertical test well drilled to an unproductive shallow horizon.

(3) Does not include one gross (one net) wellbore abandoned in 2016 and plugged in 2017 due to mechanical failure.

The figures in the table above do not include 16 gross (15.0 net) wells that were in the process of being drilled or completed, or which were awaiting completion at December 31, 2017.

Productive Wells

As of December 31, 2017, we owned an average unweighted working interest of 94% in 100 gross (94.0 net) productive wells and a minimal royalty interest in 19 additional wells. Our wells are oil wells that also produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities.

Transportation and Marketing

We are party to a long-term oil gathering agreement entered into in 2015 pursuant to which we dedicated all of our oil production from our Whiskey River and Cochise acreage. In May 2017, we amended our oil gathering agreement to include all of our Big Tex acreage. We sell substantially all of our oil production pursuant to short-term marketing agreements. We sell substantially all of our natural gas from our Cochise acreage under a long-term gathering and processing agreement entered into in September 2015, and substantially all of our natural gas from our Whiskey River acreage under a long-term gathering and processing agreement entered into in October 2016. We sell substantially all of our natural gas from our Big Tex acreage pursuant to a short-term gathering and processing agreement expiring in the fall of 2018. Substantially all of our natural gas production is transported from the wellhead by third-party gathering lines to natural gas processing facilities. None of our sales and transportation agreements contain minimum volume commitments or other similar provisions.

Major Customers

We sell our oil, natural gas and NGL production to purchasers at market prices. We sell our production to a relatively small number of customers, as is customary in our business. For 2017, revenues from Trafigura Trading, LLC and Sunoco Partners Marketing accounted for approximately 78% and 11%, respectively, of our total revenue. During 2017, no other purchaser accounted for 10% or more of our revenue. The loss of either of these purchasers could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil, natural gas and NGLs, and the availability of other purchasers, we believe that the loss of any of our purchasers would not have a long-term material adverse effect on our financial condition and results of operations because oil, natural gas and NGLs are fungible products with well-established markets.

Infrastructure

Our infrastructure strategy includes owning sufficient tracts of surface acreage to (i) allow us to control fresh water supply for drilling and completions, (ii) provide ease of pipeline installation, (iii) allow construction of storage for both fresh and produced water and (iv) simplify construction of facilities for disposal of flowback and produced water. In addition, we have supplemental agreements that provide for fresh water sourcing and produced water storage and disposal services from adjacent landowners. As of December 31, 2017, we had approximately 4,527 net surface acres on which our installed and contracted capacities were approximately (i) 8.1 MMBbl of water storage capacity, (ii) 30 miles of fresh water pipelines and 80 miles of produced water pipelines, which allows us to largely eliminate water trucking in all phases of our operation, (iii) 250 MBbl/d of water sourcing capacity and (iv) 190 MBbl/d of water disposal capacity. Accordingly, we have disposal capacity of approximately two times our current produced water volumes and sufficient sources of fresh water to support our drilling program, and we believe our water infrastructure is sufficient to support double our current rig count. This infrastructure position provides important cost advantages compared to utilizing third-party services.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

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

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas and refinery turnaround, and summer driving season affects demand for, and prices of crude oil. The prices of both oil and natural gas are heavily dependent on prevailing and expectations of future supply and demand factors, including current domestic and worldwide storage of each commodity and may not follow a seasonal pattern. Due to seasonal fluctuations or the other above factors impacting pricing, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Title to Properties

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

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

We believe 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 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 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.

Oil and Natural Gas Leases

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

Regulation of the Oil and Natural Gas Industry

General

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the development and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past noncompliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. In addition, policies, proposals and proceedings that affect the oil and natural gas industry may continue to change under the current political environment. We cannot predict when or whether any such proposals may become effective. We do not believe we would be affected by any such action materially differently than similarly situated competitors.

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in Texas, which regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density and plugging and abandonment of wells. The effect of these regulations could limit the amount of oil and natural gas that we can produce from our wells and could limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. We do not believe we are impacted any differently by these regulations than similarly situated competitors. The failure to comply with these rules and regulations can result in substantial penalties.

Regulation of Sales and Transportation of Oil

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and NGLs, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirements.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate transportation of oil, including natural gas liquids, under the Interstate Commerce Act ("ICA"). Prices received from the sale of oil liquids may be affected by the cost of transporting those products to market. The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA"), and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 ("NGA"), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005 (the "EP Act of 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (ii) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices to FERC on Form No. 552. 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 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case by case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of getting natural gas to point of sale locations may increase. We believe the natural gas pipelines in the gathering systems we use meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of the gathering facilities we use are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational 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.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our oil and natural gas development operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

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

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (“CERCLA”), also known as the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and 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 are able to directly control the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us and result in CERCLA liability.

The Resource Conservation and Recovery Act (“RCRA”) and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the U.S. Environmental Protection Agency (the “EPA”) or state agencies under RCRA’s less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess RCRA

Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of the Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

We currently own, lease or operate numerous properties that have been used for oil and natural gas development and production activities for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum 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 recycling or 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 petroleum 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 laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Regulation

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near certain regulated waters, including navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including certain wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”) potentially following review or input by the EPA. In June 2015, the EPA and the Corps issued a new rule known as the Clean Water Rule clarifying the scope of the EPA’s and the Corps’ jurisdiction under the Clean Water Act with respect to certain types of waterbodies and classifying these waterbodies as regulated. In February 2018, the EPA issued a rule that delays the applicability of the new definition of the waters of the United States until 2020. The EPA intends to propose a rule with the definition of waters of the Unites States. To the extent the new rule expands the scope of the Clean Water Act’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in certain areas. The EPA’s rule delaying the applicability date of the new definition of waters of the United States has been challenged in federal court. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for the unauthorized discharge of dredge and fill material and oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of significant quantities of oil. We are currently undertaking a review of our properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (“OPA”), which amends and augments the oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Air Emissions

The Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as storage tanks 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, comply with stringent air permit or other 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 ("NAAQS") for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the Clean Air Act that require the reduction of volatile organic compound and methane emissions from certain fractured and refractured natural gas and oil wells for which well completion operations must be conducted through the use of reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from various equipment and processes, including production-related wet seal and reciprocating compressors pneumatic controllers and storage vessels. More recently, in May 2016, the EPA finalized rules 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 processes and requirements. See also "—Regulation of "Greenhouse Gas" Emissions." Compliance with these and other air pollution control and permitting requirements, including at the state level, has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under the Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources of GHGs. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rules impose leak detection and repair requirements intended to address methane leaks known as "fugitive emissions" from equipment, such as valves, connectors, open-ended lines, pressure-relief devices, compressors, instruments and meters. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance. The EPA has proposed a 2-year stay of the effective dates of several requirements of the rules. The federal Bureau of Land Management (the "BLM") also finalized similar rules regarding the control of methane emissions in November 2016 that apply to oil and natural gas exploration and development activities on federal and Indian leases, including committed state and private tracts in a federally approved unit or communitized agreement. The rules seek to minimize venting and flaring of emissions from storage tanks and other equipment, and also impose leak detection and repair requirements. These new and proposed rules could result in increased compliance costs on our operations. The rules are at issue in active litigation in federal court. In December 2017, the BLM published a rule to temporarily suspend or delay certain rule requirements until January 2019 (the "Suspension Rule"). The Suspension Rule was immediately challenged in federal court and, on February 22, 2018, the United States District Court for the Northern District of California enjoined the Suspension Rule, putting the original BLM venting and flaring rules into immediate effect.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant legislative activity at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference in December 2015, which the U.S. ratified in September 2016. In June 2017, President Trump announced that the United States would initiate the formal process to withdraw from the Paris Agreement. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

Finally, 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, increased volatility in seasonal temperatures, and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have asserted jurisdiction over certain aspects of the process. The EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also taken the following actions: issued final regulations under the Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and, in June 2016, published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The BLM rescinded the rule in December 2017; however, the BLM's rescission of the rule has been challenged by several states in the United States District Court for the Northern District of California. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews have been conducted or proposed that focus on environmental aspects of hydraulic fracturing practices. For example, 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 some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing activities related to water use and disposal at the federal level. These studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

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 Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. The

Railroad Commission of Texas also published a rule in October 2014 governing the permitting of disposal wells that requires the submission of detailed information related to seismicity. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from drilling wells.

ESA

The Endangered Species Act ("ESA") and, in some cases, comparable state laws were established to protect endangered and threatened species. Because listing a species as threatened or endangered pursuant to the ESA prohibits death and harassment of, and injury and harm to, the species, a listing has the effect of restricting activities that adversely affect the species and its habitat. We may conduct operations on oil and natural gas leases in areas where threatened or endangered species may exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Under the ESA, the U.S. Fish and Wildlife Service also may designate as critical habitat areas it determines are essential for the conservation of a threatened or endangered species. A critical habitat designation results in additional material restrictions to federal agency actions and authorizations, such as federal land management decisions and federal permits on non-federal lands such as permits under section 404 of the Clean Water Act. Therefore, a critical habitat designation may materially delay or prohibit land access for oil and natural gas development. The presence of, or potential presence of, threatened or endangered species, or critical habitat in areas where operations are conducted could cause us to incur increased costs from species protection measures or could result in limitations on activities that could adversely impact our ability to develop and produce reserves. If a portion of our leases are designated as critical habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Act ("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 can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

We have not experienced any material adverse effect from compliance with environmental requirements; however, there is no assurance that this will continue. We did not have any material capital or other nonrecurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2017, nor do we anticipate that such expenditures will be material in 2018 or 2019.

Related Insurance

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

Principal Executive Offices and Employees

Our principal executive offices are located at 1401 Lawrence Street, Suite 1800, Denver, Colorado, 80202, and our telephone number at that address is (720) 215-3700.

As of December 31, 2017, we had 59 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Availability of Public Filings and Internet Website

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the “Exchange Act”). The public may read and copy any materials that we file or furnish with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov.

We also make available free of charge through our website, www.jaggedpeakenergy.com, this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Form 10-K.

ITEM 1A. RISK FACTORS

The following risks and uncertainties, together with other information set forth in this Form 10-K, should be carefully considered by current and future investors in our common stock. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our common stock.

Oil, natural gas and NGL prices are volatile. A reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to market uncertainty and relatively minor changes in the supply of and demand for oil, natural gas and NGLs. Historically, oil, natural gas and NGL prices have been volatile. For example, during the period from January 1, 2014 through February 28, 2018, the WTI spot price for oil declined from a high of $107.95 per Bbl on June 20, 2014, to $26.19 per Bbl on February 11, 2016, and the Henry Hub spot price for natural gas declined from a high of $8.15 per MMBtu on February 10, 2014, to a low of $1.49 per MMBtu on March 4, 2016. Likewise, NGLs, which are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, have suffered significant recent declines in realized prices. The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital, future rate of growth and carrying value of our properties. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control, which include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas and NGLs;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries, its members and state-controlled oil companies relating to oil price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

Lower commodity prices may reduce our cash flows and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Furthermore, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate or Henry Hub strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

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 ability to access or grow production and reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue making substantial capital expenditures related to our acquisition and development projects. Our 2018 capital budget for drilling, completion and recompletion activities and facilities costs is expected to range from $560.0 million to $615.0 million, excluding potential acquisitions. In addition, our production costs may increase as we continue to use enhanced recovery techniques and other new drilling and completion technologies, which are capital intensive and may not produce oil and natural gas in paying quantities or at all. Further, we regularly evaluate potential acquisition opportunities as an important aspect of our growth strategy, and any such acquisitions we pursue could require substantial capital expenditures. We expect to fund our capital expenditures with cash on hand, cash generated by operations and borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities would be dilutive to our other stockholders. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- results of our hedging program;
- the levels of our operating expenses; and
- our ability to borrow under our credit facility and our ability to access the capital markets.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and

- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations;
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage; and
- the effectiveness of the fracture stimulation process on reservoir rock.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated, we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

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

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

- delays imposed by or resulting from compliance with regulatory requirements including limitations on wastewater disposal, additional regulation related to seismic activity, discharge of GHGs and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining materials required for our drilling activities, including drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, sand, water and other supplies;
- equipment failures, accidents or other unexpected operational events;
- lack of available and economic gathering and takeaway capacity, including gathering facilities and interconnecting transmission pipelines;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

For example, in 2017 we experienced completion delays related to frac fleet equipment reliability from our service providers, which resulted in increased completed well costs and reduced our total number of well completions. Furthermore, the results of any drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production.

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

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

As of December 31, 2017, we had identified 2,083 gross horizontal drilling locations on our acreage based on approximately 880-foot spacing in an offset pattern with five to six wells across a 640-acre section, consisting of laterals with an average length of 9,094 feet. As a result of the limitations described above, we may be unable to drill many of our identified locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "—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 ability to access or grow production and reserves." Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations.

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

The process of estimating reserves is complex. It requires interpretations of available technical data and many assumptions, including current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

It should not be assumed that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on the 12-month average of the first-day-of-the-month pricing, and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If spot prices are below such calculated amounts, using more recent prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration 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 develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

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

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including any future borrowings under our credit facility, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. 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 future indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, 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 might be required to dispose of material assets or operations to meet debt service and other obligations. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

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

Our credit agreement contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- incur liens;
- make investments;
- make loans to others;
- merge or consolidate with another entity;
- sell assets;
- make certain payments;
- enter into transactions with affiliates;
- hedge commodity prices;
- hedge interest rates; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our credit agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. For example, as described in greater detail in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility,” we are required to maintain a ratio of current assets to current liabilities of not less than 1.0 to 1.0, as defined by the Credit Agreement.

Further, under our credit agreement as of December 31, 2017, we were only permitted to hedge up to the greater of 85% of our production from proved reserves and 75% of our reasonably anticipated forecasted production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years.

The restrictions in our credit agreement 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 in our credit agreement impose on us.

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

Any significant reduction in our borrowing base under our credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually on April 1 and October 1, or during an elected quarterly redetermination. The borrowing base depends on, among other things, projected revenues from, and asset values of, the proved oil and natural gas properties securing our loan. The value of our proved reserves is dependent upon, among other things, the prevailing and expected market prices of the underlying commodities in our estimated reserves. See "—Oil, natural gas and NGL prices are volatile. A reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments" and "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." During a borrowing base redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. Our borrowing base was $425.0 million as of December 31, 2017. The most recent redetermination was completed in March 2018 and resulted in a borrowing base increase to $540.0 million.

In the future, we may not be able to access adequate funding under our credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of December 31, 2017, approximately 52% of our total net acreage was held by production or continuous drilling operations. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions of the leases or the leases are renewed. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

Our derivative activities may not effectively mitigate the impact of commodity price volatility from our cash flows and could result in financial losses or could reduce our earnings.

We enter into derivative instrument contracts for a portion of our oil production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of any derivative instruments.

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

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

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

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

Adverse weather conditions and other natural disasters may negatively affect our operating results and our ability to conduct drilling activities.

Adverse weather conditions and other natural disasters may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of our oil, natural gas and NGLs. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations. For example, in 2017 industry infrastructure impacts from Hurricane Harvey caused a portion of our wells to be shut-in for a short period of time, which reduced production and revenue from such wells for that period.

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

Water is an essential component of deep shale oil and natural gas development during both the drilling and hydraulic fracturing processes. Drought conditions in Texas have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations or dispose of or recycle water used in operations, or if the prices of water or water disposal increases dramatically, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in 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 Delaware Basin, a sub-basin of the Permian Basin, in West Texas. At December 31, 2017, 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, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. For example, since our production originates near Midland, Texas, our realizations on sales of our oil production may be affected by the Midland-Cushing price differential, which reflects the difference between the price of crude at Midland, Texas, versus the price of crude at Cushing, Oklahoma, a major hub where oil production from Midland is often transported via pipeline. The price we currently realize on barrels of oil we sell is reduced by the value of the Midland-Cushing differential, which reached as high as $21 per barrel in August 2014. If the Midland-Cushing differential, or other price differentials pursuant to which our production is subject, were to widen due to oversupply or other factors, our revenue could be negatively impacted.

We are dependent on third-party pipeline and trucking systems to transport our production and gathering and processing systems to prepare our production. The lack of available capacity in these systems could interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production depends in part on the availability, proximity and capacity of gathering, processing, pipeline and trucking systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as a lack of contracted capacity on such systems. For example, on certain occasions we have experienced high line pressure at our tank batteries with occasional flaring due to the inability of the gas gathering systems in the areas in which we operate to support the increased production of natural gas in the Permian Basin. As a result, we may be required to shut in wells due to the inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. Any significant curtailment in gathering, processing or pipeline system capacity or lack of availability of transport would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect the expected results of our drilling program, as well as our cash flow and results of operations.

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

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

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

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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

As of December 31, 2017, approximately 54% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. 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 PUDs 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 PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

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

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. We may incur noncash impairment charges in the future. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

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

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

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See “Items 1 and 2. Business and Properties—Major Customers.” We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge, release or emission of materials into the environment, health and safety aspects of our operations or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, 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.

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 connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements our business, prospects, financial condition or results of operations could be materially adversely affected.

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 development activities 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 releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and

- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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

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

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies 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;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

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

In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our credit agreement imposes certain limitations on our ability to enter into mergers or combination transactions. Our credit agreement also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

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

The accuracy of these assessments is inherently uncertain. 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 fully assess 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.

In addition, acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price, and any related increase in interest expense or other related charges.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from the drilling of wells.

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

The demand for drilling rigs, pipe and other equipment and supplies (particularly sand and other proppants), as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which industry activity had increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, had increased, as did the costs for those items. To the extent that commodity prices improve in the future, any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to resume or increase our development activities could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our cash flow and profitability. Furthermore, if we are unable to secure a sufficient number of drilling rigs at reasonable costs, we may not be able to drill all of our acreage before our leases expire.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. These costs may rise faster than increases in our revenue if commodity prices rise, or they may rise without a corresponding increase in commodity prices, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

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

Under the EP Act of 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Items 1 and 2. Business and Properties—Regulation of the Oil and Natural Gas Industry."

A change in the jurisdictional characterization of some of the natural gas assets we use by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of the natural gas assets we use, which could cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that the natural gas pipelines we use meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and are, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC policy concerning where to draw the line between activities it regulates and activities excluded from its regulation has changed. The classification and regulation of the gathering facilities we use are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

See "Items 1 and 2.—Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters—Regulation of "Greenhouse Gas" Emissions."

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

See "Items 1 and 2.—Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters—Hydraulic Fracturing Activities."

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

State and federal regulatory agencies recently have focused on a possible connection between the disposal of wastewater in underground injection wells and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. For example, in 2016, the Texas state legislature provided nearly $5 million to the University of Texas to develop and manage an earthquake monitoring system in Texas. In addition, a number of lawsuits have been filed in other states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma's Corporation Commissions Oil and Gas Division is implementing an ongoing response plan that includes reducing the amount of wastewater into certain injection areas. In March 2016, the response plan was updated to target western Oklahoma's Arbuckle disposal wells. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

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

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel. The termination of employment of senior management or technical personnel could adversely affect operations.

Our future success depends to a large extent on the services of our senior management and key employees. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise. 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.

Our variable rate indebtedness subjects us to interest rate risk and increases in interest rates could adversely affect our business.

Borrowings under our credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness and for other purposes would decrease.

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

The recently enacted U.S. tax reform legislation as well as future U.S. tax legislation could adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) that significantly reforms the Internal Revenue Code of 1986, as amended. The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See Note 8 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, or local taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

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, 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. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

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. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

Laws regulating the derivatives market could adversely affect our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Under the Dodd-Frank Act, the CFTC and the SEC have promulgated rules, and are in the process of promulgating other rules, required to implement the derivatives regulatory provisions of the Dodd-Frank Act. Among the rules currently proposed for adoption by the CFTC are proposed rules that would place limits on positions in certain core futures and economically equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. These new position limit rules are not yet final, and the impact of the final position rules on us is uncertain at this time.

The Dodd-Frank Act also made the clearing of swaps over a derivatives clearing organization mandatory and the execution of cleared swaps over a board of trade or swap execution facility mandatory, subject to certain exemptions. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. As of the date hereof, the CFTC has not yet issued notices designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the exception from mandatory clearing available to commercial end-users of swaps, if we were to have to clear any swap we enter, we might not have the same flexibility we have with the bilateral swaps we now enter and would have to post margin with the derivatives clearing organization for such cleared swaps, which could adversely our ability to execute hedges to reduce risk and protect our cash flow, could adversely affect our liquidity and could reduce cash available to us for capital expenditures.

Certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for exemptions from such margin requirements available to certain users of swaps who are non-financial end-users entering into uncleared swaps to hedge their commercial risks with respect to any swaps we enter for such purpose, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If we do not qualify for an exemption from the margin rules, we could have to post initial and variation margin with the counterparties to our swaps, which could impact our liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect our cash flow.

The full impact of the Dodd-Frank Act's swap regulatory provisions and the related rules of the CFTC and SEC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act, the existing rules and any new rules 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 derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act's swap regulatory provisions and the related rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act's swap regulatory provisions were intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us and our financial condition.

In addition, the European Union and other non-U.S. jurisdictions have implemented or may implement regulations with respect to the derivatives market, some of which impose mechanisms and restrictions similar to those arising under the Dodd-Frank Act and related rules. If we enter into swaps with counterparties based in foreign jurisdictions, we may become subject to such regulations, which could have adverse effects on our operations similar to the possible effects on our operations of the Dodd-Frank Act's swap regulatory provisions and the rules of the CFTC, SEC and U.S. banking regulators.

We operate in a litigious environment and may be involved in legal proceeding that could have an adverse effect on our results of operations and financial condition.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, and personal injury or property damage matters, in the ordinary course of our business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

The standardized measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated reserves.

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received.

In addition, our predecessor generally passed through its taxable income to its owners for income tax purposes and was not subject to U.S. federal, state or local income taxes other than franchise tax in the State of Texas. Accordingly, our standardized measure as of December 31, 2016 and 2015 does not provide for U.S. federal, state or local income taxes other than franchise tax in the State of Texas. However, following our corporate reorganization, we are subject to U.S. federal, state and local income taxes, which is reflected in the standardized measure computation as of December 31, 2017.

Therefore, the standardized measure of our estimated reserves included in this Form 10-K should not be construed as accurate estimates of the current fair value of our proved reserves.

Our business is difficult to evaluate because we have a limited operating history, and we are susceptible to the potential difficulties associated with rapid growth and expansion.

JPE LLC was formed in 2013. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

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

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

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

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.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

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, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common stock.

Quantum and its affiliates have the ability to direct the voting of a majority of our common stock, and its interests may conflict with those of our other stockholders.

As of December 31, 2017, Quantum beneficially owned approximately 68.7% of our outstanding common stock. As a result, Quantum is able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of Quantum with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, Quantum would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of Quantum. These directors' duties as employees of Quantum may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest. Furthermore, we are a party to a stockholders' agreement with Quantum, JPE Management Holdings LLC and certain current and former officers and employees. Among other things, the stockholders' agreement provides that JPE Management Holdings LLC and the current and former officers and employees party thereto will vote all of their shares of common stock in accordance with the direction of Quantum. Further, the stockholders' agreement provides Quantum with the right to designate a certain number of nominees to our board of directors so long as it and its affiliates collectively beneficially own at least 5% of the outstanding shares of our common stock.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements. Our stockholders do not have the same protections afforded to stockholders of companies that are subject to such requirements.

Quantum continues to control a majority of the combined voting power of our common stock. As a result, we are a "controlled company" within the meaning of the New York Stock Exchange ("NYSE") listing standards. Under these rules, a company of which more than 50% of the voting power is held by an individual, a group or another company is a "controlled company" and may elect not to comply with certain corporate governance requirements of the NYSE, including the requirement (1) that a majority of the board of directors consist of independent directors, (2) that we have a nominating and corporate governance committee composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities and (3) that we have a compensation committee composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities. We rely on some or all of these exemptions. As a result, we do not have a majority of independent directors or a nominating or governance committee, and our compensation committee does not consist entirely of independent directors. Accordingly, our stockholders do not have the same protections afforded to stockholders of companies subject to all of the corporate governance requirements of the NYSE.

Certain of our directors have significant duties with, and spend 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.

Certain of our directors, who are and will be responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including affiliates of Quantum) that are in the business of identifying and acquiring oil and natural gas properties. For example, five of our directors, Messrs. Davidson, Linn, VanLoh, Jr., Verma and Webster, serve as Venture Partner, Senior Advisor, Founder and Chief Executive Officer, President and Managing Director, respectively, of Quantum Energy Partners, 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 these directors may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor.

Quantum and its affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in our amended and restated certificate of incorporation could enable Quantum to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents provide that Quantum and its affiliates (including portfolio investments of Quantum and its affiliates) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, our amended and restated certificate of incorporation will, among other things:

- permit Quantum and its affiliates and our non-employee directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provide that if Quantum or any of its affiliates who is also one of our non-employee directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

Quantum or its affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to not be available to us or causing them to be more expensive for us to pursue. In addition, Quantum and its affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Quantum and its affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

Quantum and its affiliates are established participants in the oil and natural gas industry and have resources greater than ours, which may make it more difficult for us to compete with such persons with respect to commercial activities as well as for potential acquisitions. We cannot assure you that any conflicts that may arise between us and our stockholders, on the one hand, and Quantum, on the other hand, will be resolved in our favor. As a result, competition from Quantum and its affiliates could adversely impact our results of operations.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things: (i) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act; (ii) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; (iii) provide certain disclosures regarding executive compensation required of larger public companies; or (iv) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues at the end of any fiscal year, have more than $700.0 million in market value of our common stock held by non-affiliates measured as of June 30, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, stockholders and investors will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition.

Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of these other pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

Our common stock began trading on the NYSE under the symbol "JAG" on January 27, 2017. Prior to that, there was no public market for our common stock. The table below sets forth, for the periods indicated, the high and low sales prices per share of our common stock since January 27, 2017.

	High	Low
2017		
First Quarter(1)	$ 15.08	$ 11.67
Second Quarter	$ 13.99	$ 10.96
Third Quarter	$ 15.19	$ 11.52
Fourth Quarter	$ 16.55	$ 12.84

(1) For the period from January 27, 2017 through March 31, 2017.

On March 9, 2018, the closing price of our common stock as reported on the NYSE was $12.18 per share. At March 9, 2018, our outstanding shares of 213,126,310 were held by approximately 9 stockholders of record.

Dividends

We have not declared or paid any cash dividends since our inception. Covenants contained in our credit agreement place restrictions on our ability to pay cash dividends. We currently intend to retain future earnings, if any, to finance our operations and the growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

We did not purchase any shares of our common stock during the three months ended December 31, 2017.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the three months ended December 31, 2017.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected historical consolidated and combined financial data, for the periods and as of the dates indicated. Our historical results are not necessarily indicative of future results. 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 the consolidated and combined financial statements and related notes, each of which is included in this report.

	Year Ended December 31,			
(in thousands, except per share data)	**2017**	**2016**	**2015**	**2014**
Statements of Operations Data:				
Revenues				
Oil sales	$ 241,788	$ 70,078	$ 31,534	$ 14,605
Natural gas sales	9,065	2,213	948	646
NGL sales	15,571	3,068	1,329	1,029
Other operating revenues	888	1,163	40	—
Total revenues	267,312	76,522	33,851	16,280

Operating expenses				
Lease operating expenses	17,874	7,505	3,165	2,041
Gathering and transportation expenses	4,424	1,046	171	121
Production and ad valorem taxes	16,120	4,345	2,244	920
Exploration	31	2,484	11	64
Depletion, depreciation, amortization and accretion	111,049	40,417	22,685	8,444
Impairment of unproved oil and natural gas properties	373	372	6,489	1,414
General and administrative expenses (including equity-based compensation of $442,976 in 2017)	466,067	11,690	7,446	7,330
Other operating expenses	247	649	250	—
Total operating expenses	616,185	68,508	42,461	20,334
Income (loss) from operations	(348,873)	8,014	(8,610)	(4,054)
Other income (expense)				
Gain (loss) on commodity derivatives	(42,615)	(15,145)	1,323	5,375
Interest expense, net	(2,861)	(2,629)	(197)	—
Other, net	358	—	—	—
Total other income (expense)	(45,118)	(17,774)	1,126	5,375
Income (loss) before income tax	(393,991)	(9,760)	(7,484)	1,321
Income tax expense (benefit)	57,943	—	—	—
Net income (loss)	(451,934)	(9,760)	(7,484)	1,321
Less: Net loss attributable to Jagged Peak Energy LLC (predecessor)	(375,476)	(9,760)	(7,484)	1,321
Net income (loss) attributable to Jagged Peak Energy Inc. stockholders	$ (76,458)	$ —	$ —	$ —
Net income (loss) attributable to Jagged Peak Energy Inc. Stockholders per common share:				
Basic	$ (0.36)			
Diluted	$ (0.36)			
Weighted-average common shares outstanding:				
Basic	212,932			
Diluted	212,932			
Cash Flow Data:				
Net cash provided by operating activities	$ 178,871	$ 32,083	$ 20,372	$ 7,615
Net cash used in investing activities	$ (600,034)	$ (195,425)	$ (110,232)	$ (187,067)
Net cash provided by financing activities	$ 418,959	$ 160,904	$ 70,397	$ 199,800
Other Financial Data:				
Adjusted EBITDAX[(1)]	$ 203,296	$ 48,995	$ 26,510	$ 6,631

	December 31,			
(in thousands)	**2017**	**2016**	**2015**	**2014**
Balance Sheet Data:				
Cash and cash equivalents	$ 9,523	$ 11,727	$ 14,165	$ 33,628
Total oil and gas properties, net	$1,029,239	$ 473,592	$ 302,726	$ 214,188
Total assets	$1,103,428	$ 518,392	$ 327,732	$ 257,084
Senior secured revolving credit facility	$ 155,000	$ 132,000	$ 20,000	$ —
Other long-term liabilities	$ 74,608	$ 3,859	$ 779	$ 850
Total stockholders' / members' equity	$ 699,345	$ 326,112	$ 284,330	$ 240,814

(1) Adjusted EBITDAX is a non-GAAP financial measure. For a definition and discussion of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX, see below under “Non-GAAP Financial Measure.”

Non-GAAP Financial Measure

Adjusted EBITDAX

Adjusted EBITDAX is a non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDAX as net income (loss) before interest expense, net of capitalized interest, depletion, depreciation, amortization and accretion, impairment of oil and natural gas properties, exploration expense, equity-based compensation expense, income taxes and net gains or losses on derivatives less net cash from derivative settlements. Adjusted EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles ("GAAP").

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

The following table presents a reconciliation of net income (loss), our most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted EBITDAX.

	Year Ended December 31,			
(in thousands)	**2017**	**2016**	**2015**	**2014**
Reconciliation of Net income (loss) to Adjusted EBITDAX:				
Net Income (Loss)	$(451,934)	$ (9,760)	$ (7,484)	$ 1,321
Adjustments to reconcile to Adjusted EBITDAX				
Interest expense, net of capitalized	2,861	2,629	197	—
Income tax expense	57,943	—	—	—
Depletion, depreciation, amortization and accretion	111,049	40,417	22,685	8,444
Impairment of unproved oil and natural gas properties	373	372	6,489	1,414
Exploration expenses	31	2,484	11	64
(Gain) loss on commodity derivatives, net, less net cash from derivative settlements(1)	39,997	12,853	4,612	(4,612)
Equity-based compensation expense	442,976	—	—	—
Adjusted EBITDAX	$ 203,296	$ 48,995	$ 26,510	$ 6,631

(1) Has the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as cash flow hedges.

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

The following discussion and analysis should be read in conjunction with our consolidated and combined financial statements and related notes presented in this Annual Report on Form 10-K. The following discussion and analysis contains forward-looking statements, including, without limitation, statements related to 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 report, particularly in "Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to update any forward-looking statements except as otherwise required by applicable law.

In this section, references to "Jagged Peak," "the Company," "we," "us" and "our" refer to Jagged Peak Energy Inc. and its subsidiaries, after the initial public offering of Jagged Peak (the "IPO") and, prior to the IPO, to Jagged Peak Energy LLC ("JPE LLC").

Jagged Peak Energy Inc. and our Predecessor

Jagged Peak was formed in September 2016 and, prior to the consummation of the IPO, did not have historical financial operating results. For purposes of this Annual Report, our accounting predecessor reflects the results of JPE LLC, which was formed in 2013 to engage in the acquisition, development, exploration and exploitation of oil and natural gas reserves. In connection with the IPO, a corporate reorganization took place whereby JPE LLC became a wholly owned subsidiary of Jagged Peak.

Overview

We are an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves. Our operations are entirely located in the United States, within the Permian Basin of West Texas. Our primary area of focus is the southern Delaware Basin; the Delaware Basin is a sub-basin of the Permian Basin. Our acreage is located on large, contiguous blocks in the adjacent Texas counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations.

We have assembled a portfolio of contiguous acreage in the core oil window of the southern Delaware Basin. This acreage is characterized by a multi-year, oil-weighted inventory of horizontal drilling locations that provide attractive growth and return opportunities. At December 31, 2017, our acreage position was approximately 75,200 net acres. We divide our current areas of operation into three distinct project areas: Cochise, with approximately 12,900 net acres, Whiskey River, with approximately 36,000 net acres, and Big Tex, with approximately 26,300 net acres.

As of December 31, 2017, our estimated proved reserves were approximately 82.4 million MMBoe, consisting of 79% oil. We seek to maintain operational control of our properties in order to better execute on our strategy of enhancing returns through operational improvements and cost efficiencies. As the operator of approximately 97% of our acreage, we have the flexibility to manage our development program, which allows us to optimize our field-level returns and profitability.

Market Conditions

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil, natural gas and NGL production. Compared to 2016, our realized oil price for 2017 increased 18% to $48.56 per barrel, our realized natural gas price increased 9% to $2.52 per Mcf, and our realized price for NGLs increased by 60% to $25.25 per barrel between these same periods. See "Sources of Our Revenues" below for further information regarding our realized commodity prices.

As the U.S. oil and gas industry continues to confront volatile commodity prices, we experience adverse effects on our business, financial condition, results of operations, operating cash flows, liquidity and ability to finance planned capital expenditures. Lower prices may also reduce the amount of oil, natural gas and NGLs that we can produce economically and therefore, potentially lower our oil, natural gas and NGL reserves. Decreasing reserves may also reduce the borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves. Our ability to access capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, oversupply and high inventory storage levels could put downward pressure on commodity prices and have an adverse impact on our business partners, customers and lenders, potentially causing them to fail to meet their obligations to us.

Factors Affecting the Comparability of Our Results of Operations

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, primarily for the reasons described below.

Incentive Unit Awards

In conjunction with the closing of the IPO, we recognized equity-based compensation expense for: (1) a charge of $379.0 million related to management incentive units ("MIUs") in JPE LLC that vested at the time of the IPO; and (2) a charge for the year ended December 31, 2017 of $60.4 million related to shares of common stock transferred to JPE Management Holdings LLC ("Management Holdco"). Please refer to Note 6, *Equity-based Compensation*, for additional information on equity-based compensation.

Public Company Expenses

Subsequent to our IPO, we incur direct, incremental general and administrative ("G&A") expenses as a result of being a publicly traded company, including, but not limited to, costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, corporate tax return preparation, increased independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental G&A expenses are not included in our historical results of operations.

Income Taxes

As a result of our corporate reorganization, we became subject to federal and state income tax. The change in tax status required the recognition of deferred tax assets and liabilities for the temporary differences at the time of the change in status. The resulting net deferred tax liability of approximately $80.7 million was recognized as tax expense from continuing operations. For periods following completion of the corporate reorganization, we began recording income taxes associated with our status as a corporation. From the date of the corporate reorganization through December 31, 2017, we recognized $22.8 million of income tax benefit which includes the favorable impact of the Tax Act (as defined below). Please refer to Note 8, *Income Taxes*, for more information on income taxes.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), that significantly changes the federal income taxation of business entities. The Tax Act, among other things, reduces the corporate income tax rate from 35% to 21%, partially limits the deductibility of business interest expense and net operating losses, allows the immediate deduction of certain new investments instead of deductions for depreciation expense over time, and eliminates the corporate alternative minimum tax. Due principally to the elimination of the corporate alternative minimum tax and our ability to immediately deduct intangible drilling and completion expenditures, we do not anticipate paying cash income taxes in the near term.

Increased Drilling Activity

Since commencing our drilling program in late 2013, we operated an average of one horizontal drilling rig through June 2016. We began operating our second and third rigs in July of 2016. At December 31, 2017, we were operating six horizontal rigs. During 2017 we completed, or participated in completing, 51 gross (46.1 net) operated wells. Our average daily production has grown from 5,613 Boe/d in 2016 to 16,974 Boe/d in 2017. During 2017 we spent $597.5 million for drilling and completing wells and on water infrastructure costs, which included $1.6 million to purchase surface acreage. This compares to $158.5 million that we spent in 2016 for drilling, completion and infrastructure.

Our board of directors approved a capital budget for 2018 which is projected to range from $560.0 million to $615.0 million, excluding acquisitions. We expect to allocate between $540.0 million and $590.0 million of our 2018 capital budget for the drilling and completion of operated and non-operated wells, and $20.0 million to $25.0 million for water infrastructure costs, excluding any potential additions to surface acreage. At the midpoint, our 2018 capital budget is nearly flat compared to our 2017 drilling and completion spending of $597.5 million. The ultimate amount of capital that we expend may fluctuate materially based on market conditions, availability and/or attractiveness of acquisitions and our drilling results.

Summary of Operating and Financial Results

- Successfully completed, or participated in completing, 51 gross (46.1 net) wells, of which we operate 46 gross (44.3 net), all within the southern Delaware Basin;
- Increased total proved reserves by 118% to 82.4 MMBoe at December 31, 2017, and replaced 821% of 2017 production;
- Added 51.8 MMBoe of proved reserves from extensions and discoveries;
- Increased average daily production by 202% to 16,974 Boe/d, comprised of 80% oil;
- Grew oil production 193% to 13,640 barrels per day, natural gas production by 279% to 9.9 MMcf/d and NGL production rose 219% to 1,690 barrels per day;
- Production revenues increased 254% to $266.4 million;
- Increased our borrowing base from $160.0 million to $425.0 million;
- Improved cash flow from operating activities to $178.9 million from $32.1 million in the previous year;
- Incurred equity-based compensation expense of $443.0 million, all of which was noncash except for $14.7 million related to an advance made in April 2016;
- Decreased LOE per Boe from $3.65 in 2016 to $2.88 in 2017;
- Experienced a noncash derivative loss of $40.0 million;
- Incurred income tax expense of $57.9 million, which includes deferred taxes recognized upon our corporate reorganization and a reduction of our deferred taxes resulting from the Tax Act; and
- Incurred a net loss of $451.9 million, largely driven by equity-based compensation charges and income tax expense.
- Adjusted EBITDAX (non-GAAP) increased by 315% to $203.3 million for the year ended December 31, 2017 (Adjusted EBITDAX is a non-GAAP financial measure. For a definition and discussion of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX, see above under "Non-GAAP Financial Measure.")

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. In 2017, our production revenues were derived 91% from oil sales, 3% from natural gas sales and 6% from NGL sales. Our oil, natural gas and NGL revenues do not include the effects of derivatives.

Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Oil, natural gas and NGL prices are market driven and have been historically volatile, and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

The following table presents our average realized commodity prices, the effects of derivative settlements on our realized prices, and certain major U.S index prices.

	Year Ended December 31,		
	2017	2016	2015
Crude Oil (per Bbl):			
Average NYMEX price	$ 50.80	$ 43.29	$ 48.76
Realized price, before the effects of derivative settlements	$ 48.56	$ 41.18	$ 43.92
Realized price, after the effects of derivative settlements	$ 48.04	$ 39.84	$ 52.19
Natural Gas (per Mcf):			
Average NYMEX price	$ 2.99	$ 2.52	$ 2.63
Realized price	$ 2.52	$ 2.32	$ 2.35
NGLs (per Bbl):			
Average realized NGL price	$ 25.25	$ 15.81	$ 14.93

While quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location and transportation differentials for these products.

See "Results of Operations" below for an analysis of the impact changes in realized prices had on our revenues.

In addition to sales of oil, natural gas, and NGLs, we derive a minimal portion of our revenues from third-party sales of fresh water and produced water disposal services. These revenues are reflected as other operating revenues on the consolidated and combined statements of operations.

Production Results

The following table presents production volumes for 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
Oil (MBbls)	4,979	1,702	718
Natural gas (MMcf)	3,601	953	404
NGLs (MBbls)	617	194	89
Total (MBoe)	6,196	2,054	874
Average net daily production (Boe/d)	16,974	5,613	2,395

Production Volumes Directly Impact Our Results of Operations

As reservoir pressures decline, production from a given well or formation decreases. Growth in our cash flow, future production and reserves will depend on our ability to continue to add production and proved reserves in excess of our production decline. Accordingly, we plan to maintain our focus on adding reserves through drilling, as well as acquisitions. Our ability to add reserves through drilling projects and acquisitions is dependent on many factors, including our ability to increase our levels of cash flow from operations, borrow or raise capital, obtain regulatory approvals, procure materials, services and personnel and successfully identify and consummate acquisitions.

Operating Costs and Expenses

Costs associated with producing oil, natural gas and NGLs are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own.

Lease Operating Expenses. Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water transportation, injection and disposal, materials and supplies comprise the most significant portion of our LOE. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. Certain operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases.

We monitor our operations to ensure that we are incurring LOE at an acceptable level, including monitoring our LOE on a per Boe basis to determine if any wells or properties should be shut in, repaired, recompleted or sold. This unit rate also allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers. Although we strive to reduce our LOE, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or make acquisitions and dispositions of properties.

Gathering and Transportation Expenses. Gathering and transportation expenses largely consist of contractual costs to gather, transport and process our natural gas and NGLs. These costs may fluctuate with increases or decreases in production volumes, contractual arrangements and changes in fuel and compression costs.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold. These taxes are calculated using fixed rates established by the state taxing authorities. In general, the production taxes we pay correlate to changes in our oil, natural gas and NGL revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trend with oil and natural gas prices and vary across the different counties in which we operate.

Exploration Expenses. Exploration expenses consist of the costs of unsuccessful exploratory wells and delay rentals for leases on certain unproved properties.

Depletion, Depreciation, Amortization and Accretion. Depletion, depreciation, amortization and accretion ("DD&A") is primarily the systematic expensing of the capitalized costs incurred to acquire and develop oil and natural gas properties. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs incurred related to the acquisition, development, and successful exploration of oil and natural gas properties, and deplete these costs based on the related reserves. DD&A also includes straight-line depreciation of capitalized corporate assets and operations support equipment, as well as the accretion of asset retirement obligation ("ARO") liabilities.

Impairment of Unproved Oil and Natural Gas Properties. Impairment of unproved oil and natural gas properties represent the cost of unproved properties that will no longer be held by production or extensions of leases.

Other Operating Expenses. Other operating expenses represent water sourcing and disposal costs related to third-party sales, and other costs associated with our oil and natural gas properties.

General and Administrative. G&A consists of costs incurred for overhead, including payroll and benefits for our corporate staff, equity-based compensation, costs of maintaining our headquarters, costs of managing our production and development operations, audit, tax and other fees for professional services and legal compliance.

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

Derivative Activity

Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. As of December 31, 2017, we had entered into derivative oil swap contracts covering periods from January 1, 2018 through December 31, 2019 for approximately 7.6 MMbls of our projected oil production at a weighted average WTI oil price of $52.09 per barrel. We also have basis differential contracts between Midland, TX and Cushing, OK for the periods from January 1, 2018 through December 31, 2019 covering 8.0 MMbls at a weighted average basis differential of $(1.09) per barrel. These derivative instruments allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. Our derivative instruments provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. In the future, we may seek to hedge price risk associated with our natural gas and NGL production. See "Item 7A.—Quantitative and Qualitative Disclosure 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 expect to continue to use commodity derivative instruments to hedge our price risk in the future. Subject to restrictions in our credit agreement, our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. Under our Amended and Restated Credit Facility as of December 31, 2017, we can hedge up to the greater of 85% of our production from proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Revenues

Oil and Natural Gas Revenues. The following table provides the components of our production revenues for the years ended December 31, 2017 and 2016, as well as each period's respective average prices and production volumes:

(in thousands or as indicated)	Year Ended December 31, 2017	Year Ended December 31, 2016	Change	% Change
Production Revenues:				
Oil sales	$ 241,788	$ 70,078	$ 171,710	245%
Natural gas sales	9,065	2,213	6,852	310%
NGL sales	15,571	3,068	12,503	408%
Total production revenues	$ 266,424	$ 75,359	$ 191,065	254%
Average sales price(1):				
Oil (per Bbl)	$ 48.56	$ 41.18	$ 7.38	18%
Natural gas (per Mcf)	$ 2.52	$ 2.32	$ 0.20	9%
NGLs (per Bbl)	$ 25.25	$ 15.81	$ 9.44	60%
Total (per Boe)	$ 43.00	$ 36.68	$ 6.32	17%
Production volumes:				
Oil (MBbls)	4,979	1,702	3,277	193%
Natural gas (MMcf)	3,601	953	2,648	278%
NGLs (MBbls)	617	194	423	218%
Total (MBoe)	6,196	2,054	4,142	202%
Average daily production volume:				
Oil (Bbls/d)	13,640	4,649	8,991	193%
Natural gas (Mcf/d)	9,865	2,603	7,262	279%
NGLs (Bbls/d)	1,690	530	1,160	219%
Total (Boe/d)	16,974	5,613	11,361	202%

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

As reflected in the table above, our total production revenue for 2017 was 254%, or $191.1 million, higher than that of 2016. The increase in 2017 compared to 2016 is due to higher sales volumes, along with higher realized commodity prices during 2017. Our aggregate production volumes in 2017 were 6,196 MBoe, comprised of 80% oil, 10% natural gas and 10% NGLs. This represents an increase of 202% from 2016 aggregate production volumes of 2,054 MBoe.

Increased production volumes accounted for an approximate $147.8 million increase in year-over-year production revenues, while increases in our total equivalent prices accounted for an approximate $43.3 million increase in year-over-year production revenues. Production increases are largely related to our active drilling program, which added 46.1 net wells that began production during 2017.

Oil sales increased 245%, or $171.7 million, due to a 193% increase in production volumes and an 18% increase in the average realized price for 2017 compared to the prior year. Natural gas sales increased 310%, or $6.9 million, due to a 278% increase in volumes in 2017 and a 9% increase in the average sales price. NGL sales increased 408%, or $12.5 million, due to a 218% increase in sales volumes, as well as a 60% increase in the average realized price for 2017. The increase in average realized price is due to increased market prices for NGLs, particularly for propane, which constitutes the largest component, by value, of our NGLs. In addition, since June 2017 we have experienced ethane rejection, which leaves ethane in the residue gas stream and increases the average realized price of NGLs per barrel.

Other Operating Revenues. Other operating revenues relate to third-party sales of fresh water and water disposal services. During 2017 and 2016, we recognized other operating revenue of $0.9 million and $1.2 million, respectively. The change year-over-year is due to fluctuating sales of our excess fresh water and water disposal capacity between periods.

Operating Expenses

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

(in thousands, except per Boe)	Year Ended December 31, 2017	2016	Change	% Change	Per Boe 2017	2016
Lease operating expenses	$ 17,874	$ 7,505	$ 10,369	138 %	$ 2.88	$ 3.65
Gathering and transportation expenses	4,424	1,046	3,378	323 %	$ 0.71	$ 0.51
Production and ad valorem taxes	16,120	4,345	11,775	271 %	$ 2.60	$ 2.12
Exploration	31	2,484	(2,453)	(99)%	$ 0.01	$ 1.21
Depletion, depreciation, amortization and accretion	111,049	40,417	70,632	175 %	$ 17.92	$ 19.67
Impairment of unproved oil and natural gas properties	373	372	1	— %	NM	NM
Other operating expenses	247	649	(402)	(62)%	$ 0.04	$ 0.32
General and administrative (before equity-based compensation)	23,091	11,690	11,401	98 %	$ 3.73	$ 5.69
Total operating expenses (before equity-based compensation)	173,209	68,508	104,701	153 %	$ 27.95	$ 33.35
Equity-based compensation	442,976	—	442,976			
Total operating expenses	$ 616,185	$ 68,508	$ 547,677			

NM—Not meaningful.

Lease Operating Expenses. Our LOE varies in conjunction with our level of production, the timing of our workover expenses and variations in industry activity that cause fluctuations in service provider costs. LOE increased 138% to $17.9 million in 2017, compared to $7.5 million for 2016. The increase largely relates to our increased production and well counts between periods that resulted in higher costs for equipment repair and maintenance, contract labor, chemicals, electricity, water disposal and equipment rental. LOE per Boe decreased 21% to $2.88 during 2017 compared to 2016, primarily due to fixed costs and the impact of the 202% increase in production between the two periods, largely coming from the addition of early-life high-producing, low-operating cost wells.

Gathering and Transportation Expenses. Gathering and transportation expenses increased $3.4 million during 2017 compared to 2016 primarily due to increased production. In addition, we experienced an increase in our per unit gathering and transportation expense. The period over period increase in our per unit gathering and transportation expense is due to an increase in natural gas production under our fixed fee contracts, as opposed to our percent-of-proceeds contracts. Under percent-of-proceeds contracts, we receive a percentage of the total proceeds received by the marketer, which is net of gathering and transportation costs. Conversely, under our fixed fee natural gas marketing contracts, our gas sales revenue is determined after transporting gas to a downstream sales point and we are separately charged for the associated gathering and transportation costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 271% between 2017 and 2016, from $4.3 million in 2016 to $16.1 million in 2017. The increase in production taxes is due to an increase in revenues, and the increase in ad valorem taxes relates to the addition of multiple new high-volume wells.

Exploration. The $2.5 million decrease in exploration expense between 2016 and 2017, is due to decreases in delay rentals on certain unproved properties of $1.3 million, as well as exploratory dry hole costs of $1.2 million incurred in 2016. The exploratory dry hole costs related to an unproductive vertical test well drilled to a shallow horizon.

Depletion, Depreciation, Amortization and Accretion. DD&A expense increased $70.6 million, or 175%, during 2017 compared to 2016. The increase in DD&A expense was largely due to an increase in production, partially offset by a decrease in our DD&A rate. Our DD&A rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The DD&A rate per Boe decreased 9% to $17.92 per Boe, compared to $19.67 per Boe in 2016. The decrease in our DD&A rate was largely due to an increase in reserve volumes due to continued successful drilling activities, whereas the rate of increase in capitalized costs related to those drilling activities was lower than the rate of reserve increase.

Impairment of Unproved Oil and Natural Gas Properties. We incurred $0.4 million of impairment costs in 2017 and 2016, which were primarily due to the expiration of certain leases on unproved properties. No impairments were recorded on proved properties during 2017 and 2016.

Other Operating Expenses. Other operating expenses decreased $0.4 million to $0.2 million in 2017 from $0.6 million in 2016. The $0.2 million of other operating expenses in 2017 was primarily due to sales of fresh water and water disposal to third parties. During 2016, other operating expenses of $0.6 million related to rig termination fees of $0.2 million and $0.4 million of costs related to selling fresh water and water disposal.

General and Administrative and equity-based compensation. G&A (excluding equity-based compensation) increased 98% to $23.1 million for the year ended December 31, 2017, from $11.7 million for the same period of 2016. The increase is primarily due to a $9.2 million increase in costs related to salaries, employee benefits, contract personnel and other general business expenses required to support the growth of our capital program and production levels. The number of our full-time employees increased from 23 at January 1, 2016 to 59 at December 31, 2017. Additionally, we incurred $1.0 million in higher audit, tax and legal fees, which increases are largely a result of becoming a publicly traded company.

Equity-based compensation expense for the year ended December 31, 2017 was $443.0 million, as summarized in the table below:

(in thousands)		
Incentive unit awards	$	439,411
Restricted stock unit awards		2,068
Performance stock unit awards		1,497
Total equity-based compensation expense	$	442,976

The equity-based compensation expense for the incentive unit awards relates to the common stock transferred to Management Holdco, which is subject to the terms of the amended and restated JPE Management Holdings LLC limited liability company agreement (the “Management Holdco LLC Agreement”), and includes approximately $379.0 million of equity-based compensation expense relative to the common stock issued to MIU holders that vested upon the IPO. Also included in the $439.4 million is $22.2 million of equity-based compensation recognized during the first quarter of 2017 related to incentive unit awards, which were modified in conjunction with a March 2017 separation agreement of a former executive officer. The restricted stock unit (“RSUs”) and performance stock unit (“PSUs”) awards were granted throughout 2017. We expect to recognize additional noncash compensation expense of approximately $10.2 million over approximately 2.1 years for the RSUs and PSUs.

In February 2018, certain employees notified the Company of their desire to terminate their employment. Under the terms of the Management Holdco LLC Agreement, upon voluntary termination of employment by an incentive unit award holder, the Board of Directors has the discretion to allow outstanding unvested incentive unit awards to immediately vest, to continue to vest post-termination, and/or to be automatically forfeited, or any combination thereof. Any forfeited incentive units are reallocated to the remaining incentive unit holders employed by the Company. In February 2018, the Board of Directors modified these employees’ unvested incentive units to either immediately accelerate vesting, in the case of retiring employees, or continue to vest post-termination under the original vesting period. The Company determined that these are accounted for as modifications under ASC 718 in the first quarter of 2018. As a result of these modifications to the service requirements, the Company determined that, for accounting purposes under ASC 718, the incentive unit awards allocated at IPO no longer met the substantive service condition, and that any previously unrecognized equity-based compensation expense should be recognized immediately. The acceleration of all previously unrecognized equity-based compensation expense for incentive unit awards allocated at the time of the IPO will result in the recognition of approximately $71.2 million of noncash equity-based compensation expense in the first quarter of 2018. This accounting does not alter the legal service obligations under the Management Holdco LLC Agreement for remaining employees whose awards were not modified. Equity-based compensation expense recognition related to incentive unit awards that were unallocated at the time of the IPO is unaffected.

Other Income and Expense

The following table summarizes our other income and expenses for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2017**	**2016**	**Change**
Gain (loss) on commodity derivatives	$ (42,615)	$ (15,145)	$ (27,470)
Interest expense, net	(2,861)	(2,629)	(232)
Other, net	358	—	358
Total other income (expense)	$ (45,118)	$ (17,774)	$ (27,344)

Gain (loss) on Commodity Derivatives. Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement, if any, of the instruments. As a result, settlements on the contracts are included as a component of other income and expense as either a net gain or loss on noncash derivative instruments. To the extent the future commodity price outlook declines between measurement periods, we will have noncash mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have noncash mark-to-market losses.

The following table sets forth the net gain (loss) from settlements and changes in the fair value of our derivative contracts, as well as the net cash receipts (payments) on settlements for the years ended December 31, 2017 and 2016:

(in thousands)	**2017**	**2016**
Gain (loss) on derivatives instruments, net	$ (42,615)	$ (15,145)
Net cash receipts (payments) on settled derivatives	$ (2,618)	$ (2,292)

Interest Expense, net. Interest expense relates to interest on our credit facility and amortization of financing costs on this facility, net of capitalized interest. During 2017 and 2016, we recorded $2.9 million and $2.6 million, respectively, of interest expense, net of capitalized interest, related to borrowings on our credit facility. Interest expense includes interest paid on the outstanding balance of the credit facility, commitment fees paid on the unused borrowing base, and amortization of debt issuance costs. The terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments. The increased interest expense year over year primarily relates to higher commitment fees paid during 2017, which resulted from a higher borrowing base throughout the year. Our average borrowing base during 2017 was $276.3 million compared to $85.4 million in 2016. Interest expense also increased as a result of higher amortization of debt issuance costs, which related to additional financing costs incurred throughout 2017 related to borrowing base increases. These increases were partially offset by a decrease in interest paid, as our average outstanding debt balance during 2017 was $44.8 million, compared to an average outstanding balance of $71.4 million during 2016.

Income tax expense (benefit)

Income tax expense of $57.9 million in 2017 is a result of our change in tax status to a C-corporation, subject to U.S. federal and state income tax, as part of the corporate reorganization. Our predecessor was a pass-through entity subject only to the Texas margin tax at a statutory rate of up to 1.0%, and was not subject to U.S. federal income tax. Further, our predecessor did not have taxable net income for purposes of calculating 2016 Texas franchise tax.

Upon the change in tax status, we established an $80.7 million provision for deferred income taxes, which was recognized as income tax expense. Subsequent to the change in tax status, we recognized $14.5 million of income tax expense. Our total deferred income taxes were reduced in the fourth quarter by $37.3 million as a result of the favorable impact of the Tax Act. As a result of the Tax Act, income taxes in 2018 and beyond will be calculated using the 21% corporate tax rate.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Revenues

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

	Year Ended December 31,			
(in thousands or as indicated)	2016	2015	Change	% Change
Production Revenues:				
Oil sales	$ 70,078	$ 31,534	$ 38,544	122 %
Natural gas sales	2,213	948	1,265	133 %
NGL sales	3,068	1,329	1,739	131 %
Total production revenues	$ 75,359	$ 33,811	$ 41,548	123 %
Average sales price(1):				
Oil (per Bbl)	$ 41.18	$ 43.92	$ (2.74)	(6)%
Natural gas (per Mcf)	$ 2.32	$ 2.35	$ (0.03)	(1)%
NGLs (per Bbl)	$ 15.81	$ 14.93	$ 0.88	6 %
Total (per Boe)	$ 36.68	$ 38.69	$ (2.01)	(5)%
Production volumes:				
Oil (MBbls)	1,702	718	984	137 %
Natural gas (MMcf)	953	404	549	136 %
NGLs (MBbls)	194	89	105	118 %
Total (MBoe)	2,054	874	1,180	135 %
Average daily production volume:				
Oil (Bbls/d)	4,649	1,967	2,682	136 %
Natural gas (Mcf/d)	2,603	1,107	1,496	135 %
NGLs (Bbls/d)	530	244	286	117 %
Total (Boe/d)	5,613	2,395	3,218	134 %

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

As reflected in the table above, our total production revenue for 2016 was 123%, or $41.5 million, higher than that of 2015. The increase is primarily due to higher sales volumes, partially offset by decreased revenues from lower realized commodity prices during 2016. Our aggregate production volumes in 2016 were 2,054 MBoe, comprised of 83% oil, 8% natural gas and 9% NGLs. This represents an increase of 135% over 2015 aggregate production volumes of 874 MBoe.

Increased production volumes accounted for an approximate $46.0 million increase in year-over-year production revenues, and decreases in our total equivalent prices accounted for an approximate $4.5 million decrease in year-over-year production revenues. Production increases are largely related to our drilling program, which added 10.9 net wells that began production during 2016.

Oil sales increased 122%, or $38.5 million, due to a 137% increase in production volumes, partially offset by a 6% decrease in the average realized price for 2016 as compared to the prior year. Natural gas sales increased 133%, or $1.3 million, primarily due to a 136% increase in volumes in 2016, somewhat offset by a 1% decrease in the average sales price. NGL sales increased 131%, or $1.7 million, primarily due to a 118% increase in sales volumes, as well as a 6% increase in the average realized price for 2016.

Other Operating Revenues. Other operating revenues relate to third-party sales of fresh water and water disposal services. During 2016 and 2015, we recognized other operating revenue of $1.2 million and $40 thousand, respectively. The increase year-over-year is due to increased sales of our excess fresh water and water disposal capacity between periods.

Operating Expenses

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

(in thousands, except per Boe)	Year Ended December 31, 2016	2015	Change	% Change	Per Boe 2016	2015
Lease operating expenses	$ 7,505	3,165	$ 4,340	137 %	$ 3.65	$ 3.62
Gathering and transportation expenses	1,046	171	875	512 %	$ 0.51	$ 0.20
Production and ad valorem taxes	4,345	2,244	2,101	94 %	$ 2.12	$ 2.57
Exploration	2,484	11	2,473	22,482 %	$ 1.21	$ 0.01
Depletion, depreciation, amortization and accretion	40,417	22,685	17,732	78 %	$ 19.67	$ 25.94
Impairment of unproved oil and natural gas properties	372	6,489	(6,117)	(94)%	NM	NM
Other operating expenses	649	250	399	160 %	$ 0.32	$ 0.29
General and administrative	11,690	7,446	4,244	57 %	$ 5.69	$ 8.52
Total operating expenses	$ 68,508	$ 42,461	$ 26,047	61 %	$ 33.35	$ 48.57

NM—Not meaningful.

Lease Operating Expenses. Our LOE varies in conjunction with our level of production, the timing of our workover expenses and variations in industry activity that cause fluctuations in service provider costs. LOE increased 137% to $7.5 million in 2016, as compared to $3.2 million in 2015. The increase was primarily related to higher production between periods, which resulted in additional costs for contract labor, chemicals and electricity. In addition, in 2016 we enhanced our repair and maintenance program for our operated wells, resulting in an overall increase in workover LOE costs. While our LOE costs increased 137% overall from 2015 to 2016, our 2016 LOE per Boe of $3.65 increased only slightly compared with 2015.

Gathering and Transportation Expenses. Gathering and transportation expenses increased $0.9 million during 2016 as compared to 2015 due to increased production as well as an increase in our per unit gathering and transportation expense. The period over period increase in our per unit gathering and transportation expense was due to a shift away from marketing our natural gas under percent-of-proceeds contracts toward marketing a larger portion of our natural gas under fixed fee contracts. Under percent-of-proceeds contracts, we receive a percentage of the total proceeds received by the marketer, which is net of transportation expense and do not book a separate charge for gathering and transportation expense. Conversely, under our fixed fee natural gas marketing contracts, we receive a topline revenue amount and are separately charged for the associated gathering and transportation expense.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 94% during 2016, from $2.2 million in 2015 to $4.3 million in 2016. The increase in production taxes is primarily due to an increase in revenues and the increase in ad valorem taxes relates to the addition of several new high-volume wells.

Exploration. The $2.5 million increase in exploration expense between 2016 and 2015, is due to increases in delay rentals on certain unproved properties of $1.3 million, as well as exploratory dry hole costs of $1.2 million incurred in 2016. The exploratory dry hole costs related to an unproductive vertical test well drilled to a shallow horizon.

Depletion, Depreciation, Amortization and Accretion. Our DD&A expense increased $17.7 million, or 78%, from 2015 to 2016. The increase in DD&A was largely due to an increase in production, partially offset by a decrease in our DD&A rate. Our DD&A rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The DD&A rate per Boe decreased 24% to $19.67 per Boe, compared to $25.94 per Boe in 2015. The decrease in our DD&A rate was largely due to an increase in reserve volumes due to successful drilling activities, whereas the rate of increase in capitalized costs related to these drilling activities was lower than the rate of reserve increase.

Impairment of Unproved Oil and Natural Gas Properties. We incurred $0.4 million and $6.5 million of impairment expense in 2016 and 2015, respectively, which related to the expiration of certain leases on unproved properties. No impairments were recorded on proved properties during 2016 and 2015.

Other Operating Expenses. Our other operating expenses increased by $0.4 million from $0.3 million in 2015 to $0.6 million in 2016. The $0.6 million of other operating expense in 2016 included $0.4 million of costs related to sales of fresh water and water disposal to third parties, and $0.2 million for the early termination of a rig contract. In 2015, we incurred $0.3 million of other operating expenses in conjunction with the early termination of a rig contract.

General and Administrative. G&A increased 57% to $11.7 million for the year ended December 31, 2016, from $7.4 million for the same period of 2015. The increase was primarily due to a $2.6 million increase in employee and contractor costs required to manage our expanding capital program and production levels. The remaining increase was principally due to a $1.0 million employee separation payment paid in the first quarter of 2016, and $0.4 million of additional legal, audit, and tax expenses.

Other Income and Expenses

The following table summarizes our other income and expenses for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2016**	**2015**	**Change**
Gain (loss) on commodity derivatives	$ (15,145)	$ 1,323	$ (16,468)
Interest expense, net	(2,629)	(197)	(2,432)
Other, net	—	—	—
Total other income (expense)	$ (17,774)	$ 1,126	$ (18,900)

Gain (loss) on Commodity Derivatives. Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement, if any, of the instruments. As a result, settlements on the contracts are included as a component of other income and expense as either a net gain or loss on noncash derivative instruments. To the extent the future commodity price outlook declines between measurement periods, we will have noncash mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have noncash mark-to-market losses.

The following table sets forth the net gain (loss) from settlements and changes in the fair value of our derivative contracts, as well as the net cash receipts (payments) on settlements for the years ended December 31, 2016 and 2015:

(in thousands)	**2016**	**2015**
Gain (loss) on derivatives instruments, net	$ (15,145)	$ 1,323
Net cash receipts (payments) on settled derivatives	$ (2,292)	$ 5,935

Interest Expense and Other. Interest expense relates to interest on our credit facility and amortization of financing costs on this facility. During 2016 and 2015, we recorded $2.6 million and $0.2 million, respectively, of interest expense related to the borrowings on our credit facility. Interest expense for these periods was net of capitalized interest of $0.1 million and $0.03 million, respectively. The increase in interest expense in 2016 is due to additional borrowings on our credit facility, as we began borrowing on our credit facility in July 2015.

Income tax expense (benefit)

Our predecessor was a pass-through entity subject only to the Texas margin tax at a statutory rate of up to 1.0%, and was not subject to U.S. federal income tax. Further, our predecessor did not have taxable net income for purposes of calculating 2016 or 2015 Texas franchise tax.

Liquidity and Capital Resources

Historically, our predecessor's primary sources of liquidity were capital contributions from our equity owners, borrowings under our predecessor's credit facility and cash flows from operations. During the year ended 2017, our primary sources of liquidity were the proceeds from the IPO of $397.0 million, cash flows from operations of $178.9 million and net borrowings under our credit facility of $23.0 million. Historically, our predecessor's and our primary use of cash has been for the development and acquisition of oil, natural gas and NGL properties, as well as for development of water sourcing and disposal infrastructure. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities, and liquidity requirements. Our future success in growing proved reserves, production and balancing the long-term development of our assets with a focus on generating attractive corporate-level returns will be highly dependent on the capital resources available to us.

Capital Expenditures

Capital expenditures for oil and gas acquisitions, exploration, development and infrastructure activities are summarized below:

	Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Acquisitions			
Proved properties	$ —	$ 7,482	$ —
Unproved properties[1]	69,083	47,468	10,915
Development costs	567,555	144,786	104,213
Infrastructure costs[2]	29,909	13,713	11,801
Exploration costs	31	1,673	852
Total oil and gas capital expenditures	$ 666,578	$ 215,122	$ 127,781

(1) Relates to acquisition of undeveloped leaseholds and oil and natural gas mineral interest leasing activity.
(2) Includes surface acreage purchased during 2017, 2016 and 2015 of $1.6 million, $3.1 million and $1.0 million, respectively.

For the years ended December 31, 2017, 2016 and 2015, our capital expenditures have been focused on the development of our properties in the southern Delaware Basin. As of December 31, 2017, we had approximately 87,600 gross (75,200 net) acres.

The following table reflects wells that began producing in the periods indicated:

	Year Ended December 31,		
	2017	**2016**	**2015**
Gross wells			
Operated	46	11	7
Non-operated	5	—	—
	51	11	7
Net wells			
Operated	44.3	10.9	6.4
Non-operated	1.8	—	—
	46.1	10.9	6.4

At December 31, 2017, we were in the process of drilling nine gross (8.6 net) wells and had seven gross (6.4 net) wells waiting on completion, including three gross (2.8 net) wells that were in process of being completed.

2018 Capital Budget

Our 2018 capital budget for development of oil and gas properties and infrastructure is as follows:

(in millions)			
Drilling and completion	$ 540.0	—	$ 590.0
Water infrastructure	20.0	—	25.0
Total	$ 560.0	—	$ 615.0

Our 2018 capital budget excludes potential leasehold and/or surface acreage additions. Based on our 2018 capital budget, we expect to spud approximately 40 to 45 gross operated wells, and complete and bring online 42 to 46 gross operated wells. Additionally, the Company expects to participate in 6 to 9 gross non-operated wells. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities and commodity prices.

Because we operate a high percentage of our acreage, capital expenditure amounts and timing are largely discretionary and within our control. We determine our 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. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations. Furthermore, we may be required to remove some portion of our reserves currently booked as proved undeveloped reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and additional borrowing capacity under our credit facility to execute our planned 2018 capital program. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. If we require additional capital funding for capital expenditures, acquisitions or other reasons, we may seek such capital through borrowings under our credit facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Working Capital

Our working capital, which we define as current assets minus current liabilities, fluctuates primarily as a result of our realized commodity prices, increases or decreases in our production volumes, changes in receivables and payables related to our operating and development of oil and natural gas activities, changes in our hedging activities and changes in our cash and cash equivalents. At December 31, 2017, we had a working capital deficit of $113.4 million, a decrease of $82.5 million compared to a working capital deficit of $31.0 million at December 31, 2016. The decrease is primarily the result of a $91.0 million increase to accrued capital expenditures and other accruals associated with increased development of our oil and natural gas properties, as well as a decrease in the net fair value of our unsettled commodity derivatives of $32.2 million. These decreases in working capital were partially offset by an increase in our accounts receivable of $40.4 million.

We may incur additional working capital deficits in the future due to increases in liabilities related to our drilling program or further decreases in the value of our current commodity derivatives. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents balance totaled approximately $9.5 million and $11.7 million at December 31, 2017 and 2016, respectively. We expect that our cash flows from operating activities, access to capital markets and availability under Amendment No. 2 of our Amended and Restated Credit Facility (described and defined below) will be sufficient to fund our working capital needs. 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.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Net cash provided by operating activities	$ 178,871	$ 32,083	$ 20,372
Net cash used in investing activities	$ (600,034)	$ (195,425)	$ (110,232)
Net cash provided by financing activities	$ 418,959	$ 160,904	$ 70,397

Operating Activities. Net cash provided by operating activities is primarily affected by the price of oil, natural gas and NGLs, production volumes and changes in working capital.

The $146.8 million increase in 2017 compared to 2016 primarily resulted from a $190.8 million increase in revenues, which resulted from a 202% increase in volumes and a 17% increase in the average price received per Boe. This was partially offset by $22.7 million of higher cash operating costs primarily due to increased production, and $11.4 million of increased cash G&A costs due to additional personnel.

The $11.7 million increase in 2016 compared to 2015 is primarily due to a 126%, or $42.7 million, increase in revenues, which resulted primarily from a 135% increase in volumes. Net cash provided by operating activities also increased in 2016 due to a favorable change in operating assets and liabilities of $7.5 million. These increases were partially offset by a $14.7 million nonrecurring management incentive advance, an $8.2 million decrease in net cash received for settlements of derivatives, and higher operating costs primarily due to increased production.

Investing Activities. Cash flows from investing activities primarily consist of the acquisition, exploration, and development of oil and natural gas properties, net of dispositions of oil and natural gas properties.

During 2017, net cash flow used in investing activities was $600.0 million, which included investments in developing our acreage of $523.6 million and leasehold and acquisition costs of $73.5 million. In 2016, net cash used for investing activities of $195.4 million included $139.6 million and $54.7 million for the development and acquisition of oil and natural gas properties, respectively. In 2015, net cash used for investing activities included $96.7 million and $13.7 million for the development and acquisition of oil and natural gas properties, respectively.

Financing Activities. Net cash provided by financing activities includes the issuance of equity and debt transactions.

Net cash provided by financing activities during 2017 was primarily due to $398.4 million of net proceeds from the sale of common stock in the IPO and $165.0 million of borrowings on our credit facility, which was partially offset by a repayment on our credit facility of $142.0 million after the IPO. Net cash provided by financing activities in 2016 included $51.5 million of cash provided by contributions from JPE LLC members and $112.0 million of borrowings under our credit facility. Net cash provided by financing activities in 2015 included $51.0 million of cash provided by member unit issuances and $20.0 million of borrowings under our credit facility.

Credit Facility

On June 19, 2015, our predecessor entered into a credit agreement that provided for a senior secured revolving credit facility with an aggregate commitment of $500.0 million (subject to the then-effective borrowing base). In January 2017, the borrowing base increased to $180.0 million. In connection with the IPO, we, as parent guarantor, and our predecessor, as borrower, entered into an Amended and Restated Credit Facility. The Amended and Restated Credit Facility matures on February 1, 2022. After giving effect to such amendment and restatement, the aggregate principal commitment increased to $1.0 billion and the borrowing base under the Amended and Restated Credit Facility remained at $180.0 million. Also in connection with the IPO, we fully repaid the outstanding borrowings under the credit facility of $142.0 million. In April 2017, the borrowing base was increased to $250.0 million, and in October 2017 we entered into Amendment No. 1 to the Amended and Restated Credit Facility which increased the borrowing base to $425.0 million. In March 2018, we entered into Amendment No. 2 to the Amended and Restated Credit Facility which extended the maturity date of the Amended and Restated Credit Facility to March 2023, increased the aggregate commitment to $1.5 billion, increased the borrowing base to $540.0 million, increased the hedging limits, and lowered the pricing grid. As of the date of this filing, we have $265.0 million outstanding, and $275.0 million available under the borrowing base.

The amount available to be borrowed under our Amended and Restated Credit Facility is subject to a borrowing base that is redetermined semiannually by each April 1 and October 1, or during an elected quarterly redetermination, by the lenders at their sole discretion. The borrowing base depends on, among other things, the volumes of our proved reserves and estimated cash flows from these reserves and our commodity hedge positions as well as any other outstanding debt. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, we could be required to immediately repay a portion of the debt outstanding under our credit agreement.

At December 31, 2017, the weighted average interest rate on borrowings under our credit facility was approximately 3.68%. We also paid a commitment fee on unused amounts of our credit facility of 0.375% to 0.50% per year on the unused portion of the borrowing base, depending on the relative amount of the loan outstanding in relation to the borrowing base. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Our credit agreement contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;

- incur liens;
- make investments;
- make loans to others;
- merge or consolidate with another entity;
- sell assets;
- make certain payments;
- enter into transactions with affiliates;
- hedge interest rates; and
- engage in certain other transactions without the prior consent of the lenders.

At December 31, 2017, our Amended and Restated Credit Facility contains financial covenants, which are measured on a quarterly basis. The covenants, as defined in the Amended and Restated Credit Facility, include requirements to comply with the following financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including unused commitments under our credit facility and excluding noncash assets related to ARO and derivatives) to our consolidated current liabilities (excluding the current portion of long-term debt under our credit agreement and noncash liabilities related to ARO obligations and derivatives), as of the last day of each fiscal quarter, of not less than 1.0 to 1.0; and
- a leverage ratio, which is the ratio of our consolidated Debt (as defined in our credit agreement) as of the last day of each fiscal quarter, subject to certain exclusions (as described in our credit agreement) to EBITDAX (as defined in our credit agreement) for the last 12 months ending on the last day of that fiscal quarter, of not greater than 4.0 to 1.0.

As of December 31, 2017, we were in compliance with all financial covenants.

Amendment No. 1 to the Amended and Restated Credit Facility permitted us to hedge up to the greater of 85% of production from proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges had a term beyond five years. Under Amendment No. 2 to the Amended and Restated Credit Facility, we are permitted to hedge up to 85% of forecasted production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 60% of our reasonably anticipated forecasted production for 25 to 60 months in the future, provided that no hedges have a term beyond five years.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2017 is provided in the following table:

	Payments Due by Period for the Year Ending December 31,						
(in thousands)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Credit facility(1)	$ —	$ —	$ —	$ —	$ 155,000	$ —	$ 155,000
Operating leases(2)	2,052	1,490	1,514	1,535	1,552	8,962	17,105
Service and purchase contracts(3)	2,380	1,287	1,285	750	—	—	5,702
Rig contracts(4)	16,054	—	—	—	—	—	16,054
Frac fleet contracts(5)	73,200	—	—	—	—	—	73,200
Total	$ 93,686	$ 2,777	$ 2,799	$ 2,285	$ 156,552	$ 8,962	$ 267,061

(1) This table does not include future commitment fees, interest expense or other costs related to our credit facility because we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of December 31, 2017, we had $155.0 million outstanding under our Amended and Restated Credit Facility and $270.0 million of borrowing capacity available.

(2) Primarily relates to the lease of our corporate offices. In January 2018, we entered into a termination agreement on our initial corporate office lease, in which we agreed to a one-time termination fee of approximately $0.3 million. Including this fee, the 2018 operating lease commitment would be $1.8 million.

(3) Primarily relates to a retail power purchase agreement and seismic data gathering contract.

(4) Relates to six drilling rig contracts as of December 31, 2017. If we were to terminate these contracts at December 31, 2017, we would be required to pay early termination penalties of approximately $7.5 million.

(5) Relates to three frac fleets under contract at December 31, 2017. The majority of the contracts allow for reassignment of the frac fleets to another operator if we were to terminate their services prior to the end of the contract, at which

point we would not be required to pay termination fees. However, if the fleets were not able to be reassigned, we would be required to pay termination fees of $57.2 million as of December 31, 2017.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated and combined financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements require 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 preparation of our consolidated and combined financial statements. Our more significant accounting policies and estimates include: impairment of oil and natural gas properties, oil, natural gas and NGL reserve quantities and standardized measure of discounted future net cash flows, derivative instruments and income taxes. We provide an expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated and combined financial statements.

A complete list of our significant accounting policies is described in Note 2, *Significant Accounting Policies and Related Matters*, to our consolidated and combined financial statements for the year ended December 31, 2017.

Impairment of Oil and Natural Gas Properties

Proved oil and natural gas properties are reviewed for impairment 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 oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties 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 fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate.

Unproved properties are periodically assessed for impairment on a property-by-property basis. We evaluate significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage, and record impairment expense for any decline in value.

Oil, Natural Gas and NGL Reserve Quantities and Standardized Measure of Discounted Future Net Cash Flows

We engage Ryder Scott, our independent petroleum engineer, to prepare our total estimated proved reserves. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves internally each quarter and Ryder Scott estimates our proved reserves annually. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenue, 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 reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

It should not be assumed that the standardized measure included in this report as of December 31, 2017 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2017 standardized measure on the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas 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 1 and 2. Business and Properties” for additional information regarding estimates of proved reserves.

Derivative Instruments

We utilize commodity derivative instruments to manage our exposure to commodity price volatility. All our commodity derivative instruments are utilized to manage price risk attributable to our expected production, and we do not enter into such instruments for speculative trading purposes. We do not designate any derivative instruments as cash flow hedges for financial reporting purposes. We record all derivative instruments on the balance sheet as either assets or liabilities measured at estimated fair value. We compute the fair value of our derivatives by computing the discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. The fair value estimates are adjusted relative to non-performance risk as appropriate. We record gains and losses from the change in fair value of derivative instruments in current earnings as they occur. We do not currently utilize any derivative instruments to manage exposure to variable interest rates, but may do so in the future.

Income Taxes

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our consolidated and combined financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance if we believe it is more likely than not such deferred tax assets will not be realized. Additionally, our federal and state income tax returns are generally not filed before the consolidated and combined financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period, as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations.

The calculation of deferred tax assets and liabilities involves uncertainties in the application of complex tax laws and regulations. We recognize the financial statement effects of a tax position when it is more likely than not, based on technical merits, that the position will be sustained upon examination.

Recently Issued Accounting Pronouncements

Please refer to Note 2, *Significant Accounting Policies and Related Matters – Recent Accounting Pronouncements*, to the consolidated and combined financial statements included elsewhere in this report for a discussion of recent accounting pronouncements and their anticipated effect on our business.

Off-Balance Sheet Arrangements

We had no material off-balance sheet arrangements as of December 31, 2017. Please read Note 10, *Commitments and Contingencies*, included in notes to the consolidated and combined financial statements included elsewhere in this report, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 7A. QUALITATIVE AND QUANTITATIVE 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 oil and natural gas prices and interest rates. 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, natural gas and NGLs production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on numerous factors beyond our control, some of which are discussed in “Item 1A. Risk Factors—Risks Related to Our Business—Oil, natural gas and NGL prices are volatile. A reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.”

Oil sales contributed 91% of our total production revenues for 2017. Natural gas sales contributed 3% and NGL sales contributed 6% of our total production revenues for 2017. Our oil, natural gas and NGL revenues do not include the effects of derivatives instruments used to mitigate price volatility. The following table shows how hypothetical changes in the realized prices we receive for our commodity sales would have impacted revenue for the periods indicated during 2017:

(in thousands)	Change in Realized Prices	Impact on Revenue		
Oil	+ / - $1.00 per barrel	+ / -	$	4,979
Natural gas	+ / - $0.10 per Mcf	+ / -	$	360
NGL	+ / - $1.00 per barrel	+ / -	$	617

Due to this volatility, we use commodity derivative instruments such as swaps and basis swaps to hedge price risk associated with a portion of our oil production. In the future, we may use commodity derivatives to hedge a portion of our natural gas or NGL production. These hedging instruments will allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. This provides increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. We may seek to hedge price risk associated with our natural gas and NGL production in the future.

Under our Amended and Restated Credit Facility as of December 31, 2017, we are permitted to hedge up to the greater of 85% of our production from proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years. Under Amendment No. 2 to the Amended and Restated Credit Facility, we are permitted to hedge up to 85% of forecasted production for up to 24 months in the future, and up to the greater of 75% of our production from proved reserves and 60% of our reasonably anticipated forecasted production for 25 to 60 months in the future, provided that no hedges have a term beyond five years.

At December 31, 2017, we had a net liability position of $52.9 million related to our derivatives in place for the years 2018 through 2019. Based on our open derivative positions at December 31, 2017, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $43.7 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $43.7 million.

See Note 3, *Derivative Instruments*, and Note 4, *Fair Value Measurements*, to our consolidated and combined financial statements included elsewhere in this report for a summary of our open derivative positions, as well as a discussion of how we determine the fair value of and account for our derivative contracts.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place have investment grade ratings, and are all lenders or affiliates of lenders under our Amended and Restated Credit Facility.

Our principal exposures to credit risk are through receivables resulting from joint interest receivables and receivables from the sale of our oil and natural gas production due to the concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our Amended and Restated Credit Facility. At December 31, 2017, we had $155.0 million of debt outstanding, all of which was under Amendment No. 1 to our Amended and Restated Credit Facility, with a weighted average interest rate of 3.68%. At December 31, 2017, borrowings under the Amendment No. to our Amended and Restated Credit Facility bore interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50%, and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranged from 1.00% to 2.00% in the case of the alternative base rate, and from 2.00% to 3.00% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We paid a commitment fee on unused amounts of our credit facility of 0.375% to 0.50% per year on the unused portion of the borrowing base, depending on the relative amount of the loan outstanding in relation to the borrowing base.

Borrowings under the Amended and Restated Credit Facility following Amendment No. 2 bear interest at a rate we elect that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50%, and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate, and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The commitment fee paid by the Company remains at 0.375% to 0.50% per year on the unused portion of the borrowing base, depending on the relative amount of the loan outstanding in relation to the borrowing base.

Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the assumed weighted average interest rate would be approximately $1.6 million per year. We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item is included in this Annual Report as set forth in the "Index to Financial Statements" on page F-1 of this report and is incorporated herein by reference.

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 Rules 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management, including our principal executive officer and principal financial officer, evaluated 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, 2017. 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 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, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. 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. 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 policies or procedures may deteriorate.

As of December 31, 2017, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control – Integrated Framework (2013)", issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that we maintained effective internal control over financial reporting as of December 31, 2017.

Attestation Report of the Registered Public Accounting Firm

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal controls over financial reporting for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 is incorporated by reference from the information in our definitive proxy statement for the 2018 Annual Meeting of Stockholders, which we will file pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2017.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (www.jaggedpeakenergy.com) under “Corporate Governance” within the “Investor Relations” section. We will provide a copy of this document to any person, without charge, upon request, by writing to us at Jagged Peak Energy Inc., Investor Relations, 1401 Lawrence Street, Suite 1800, Denver, Colorado 80202. We intend to satisfy the disclosure requirement under Item 406(c) of Regulation S-K regarding an amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on our website at the address and the location specified above.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 is incorporated by reference from the information in our definitive proxy statement for the 2018 Annual Meeting of Stockholders, which we will file pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2017.

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

Information as to Item 12 is incorporated by reference from the information in our definitive proxy statement for the 2018 Annual Meeting of Stockholders, which we will file pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2017.

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

Information as to Item 13 is incorporated by reference from the information in our definitive proxy statement for the 2018 Annual Meeting of Stockholders, which we will file pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2017.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information as to Item 14 is incorporated by reference from the information in our definitive proxy statement for the 2018 Annual Meeting of Stockholders, which we will file pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2017.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules

The consolidated and combined financial statements are listed on the Index to Financial Statements to this report beginning on page F-1.

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1††	Master Reorganization Agreement, dated January 25, 2017, by and among Jagged Peak Energy LLC, Q-Jagged Peak Energy Investment Partners LLC, Jagged Peak Energy Inc., JPE Merger Sub LLC, JPE Management Holdings LLC and the management members named therein (incorporated by reference to Exhibit 2.1 to the Company's Form 8-K filed with the SEC on January 31, 2017).
3.1	Amended and Restated Certification of Incorporation of Jagged Peak Energy Inc., filed with the Secretary of State of the State of Delaware on February 1, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Form 8-K filed with the SEC on February 7, 2017).
3.2	Amended and Restated Bylaws of Jagged Peak Energy Inc., effective February 1, 2017 (incorporated by reference to Exhibit 3.2 to the Company's Form 8-K filed with the SEC on February 7, 2017).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to the Company's Amended Registration Statement on Form S-1/A (File No. 001-37995) filed with the SEC on January 6, 2017).
4.2	Registration Rights Agreement, dated as of February 1, 2017, by and among Jagged Peak Energy Inc. and the stockholders named therein (incorporated by reference to Exhibit 4.1 to the Company's Form 8-K filed with the SEC on February 7, 2017).
4.3	Stockholders' Agreement, dated as of February 1, 2017, by and among Jagged Peak Energy Inc., Q-Jagged Peak Energy Investment Partners, LLC, JPE Management Holdings LLC, and the individuals party thereto (incorporated by reference to Exhibit 4.2 to the Company's Form 8-K filed with the SEC on February 7, 2017).
10.1	Amended and Restated Limited Liability Company Agreement of JPE Management Holdings LLC, dated February 1, 2017 (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed with the SEC on February 7, 2017).
10.2.1	Amended and Restated Credit Agreement, dated as of February 1, 2017, by and among Jagged Peak Energy Inc., as parent guarantor, Jagged Peak Energy LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders named therein (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed with the SEC on February 7, 2017).
10.2.2	Amendment No. 1, Master Assignment, and Agreement to Amended and Restated Credit Agreement, dated as of October 26, 2017, among Jagged Peak Energy LLC, as borrower, the guarantors party named therein, Wells Fargo Bank, National Association, as administrative agent and as issuing lender, the lenders named therein, the assignors named therein, and the assignees named therein (incorporated by reference to Exhibit 10.2 to the Company's Form 10-Q filed with the SEC on November 8, 2017).
10.3†	Form of Indemnification Agreement between Jagged Peak Energy Inc. and its Officers and Directors (incorporated by reference to Exhibit 10.3 to the Company's Form 10-Q filed with the SEC on May 12, 2017).
10.4†	Executive Employment Agreement, dated April 3, 2013, between Jagged Peak Energy Management LLC and Joseph. N. Jaggers (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (File No. 333-215179), filed with the SEC on December 19, 2016).
10.5†	Separation and Release Agreement, dated as of March 14, 2017, between Jagged Peak Energy Inc. and Gregory S. Hinds (incorporated by reference to Exhibit 10.4 to the Company's Form 10-Q filed with the SEC on May 12, 2017).
10.6†	Executive Severance Plan (incorporated by reference to Exhibit 10.1 to the Company's 10-Q filed with the SEC on August 10, 2017).
10.7†	Form of Employment Letter Agreement (incorporated by reference to Exhibit 10.2 to the Company's 10-Q filed with the SEC on August 10, 2017).
10.8†	Jagged Peak Energy Inc. 2017 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed with the SEC on January 31, 2017).
10.9†	Form of Director Notice of Grant of Restricted Stock Units (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed with the SEC on April 20, 2017).

10.10†	Form of Director Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.4 to the Company's Form 8-K filed with the SEC on April 20, 2017).
10.11†	Form of Employee Notice of Grant of Restricted Stock Units (incorporated by reference to Exhibit 10.5 to the Company's Form 8-K filed with the SEC on April 20, 2017).
10.12†	Form of Employee Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.6 to the Company's Form 8-K filed with the SEC on April 20, 2017).
10.13†	Form of Employee Notice of Grant of Performance Stock Units (incorporated by reference to Exhibit 10.7 to the Company's Form 8-K filed with the SEC on April 20, 2017).
10.14†	Form of Employee Performance Stock Unit Agreement (incorporated by reference to Exhibit 10.8 to the Company's Form 8-K filed with the SEC on April 20, 2017).
10.15†	Form of Series B Restricted Unit Agreement (incorporated by reference to Exhibit 10.9 to the Company's Form 8-K filed with the SEC on April 20, 2017).
21.1	Subsidiary of the Registrant.
*23.1	Consent of KPMG LLP.
*23.2	Consent of Ryder Scott Company, LP.
*31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certifications by Chief Executive Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.
**32.2	Certifications by Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.
*99.1	Ryder Scott Company, LP, Summary of Reserves at December 31, 2017.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

† Compensatory plan or arrangement.

†† Schedules and similar attachments to the Master Reorganization Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant will furnish a supplemental copy of any omitted schedule or similar attachment to the SEC upon request.

* Filed herewith.

** Furnished herewith.

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.

JAGGED PEAK ENERGY INC.

Date: March 22, 2018

By: /s/ JOSEPH N. JAGGERS

Name: Joseph N. Jaggers

Title: *Chairman, Chief Executive Officer and President*

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 indicated.

Signature	Title	Date
/s/ JOSEPH N. JAGGERS Joseph N. Jaggers	Chairman, Chief Executive Officer and President (Principal Executive Officer)	March 22, 2018
/s/ ROBERT W. HOWARD Robert W. Howard	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	March 22, 2018
/s/ SHONN D. STAHLECKER Shonn D. Stahlecker	Controller	March 22, 2018
/s/ CHARLES D. DAVIDSON Charles D. Davidson	Director	March 22, 2018
/s/ ROGER L. JARVIS Roger L. Jarvis	Director	March 22, 2018
/s/ JAMES J. KLECKNER James J. Kleckner	Director	March 22, 2018
/s/ MICHAEL C. LINN Michael C. Linn	Director	March 22, 2018
/s/ JOHN R. SULT John R. Sult	Director	March 22, 2018
/s/ S. WIL VANLOH, JR. S. Wil VanLoh, Jr.	Director	March 22, 2018
/s/ DHEERAJ VERMA Dheeraj Verma	Director	March 22, 2018
/s/ BLAKE A. WEBSTER Blake A. Webster	Director	March 22, 2018

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Jagged Peak Energy Inc.:

Opinion on the Consolidated and Combined Financial Statements

We have audited the accompanying consolidated and combined balance sheets of Jagged Peak Energy Inc. and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated and combined statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated and combined financial statements). In our opinion, the consolidated and combined financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 and combined financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated and combined 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 and combined 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 and combined financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Denver, Colorado
March 22, 2018

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,523	$ 11,727
Accounts receivable	50,734	10,327
Other current assets	806	3,412
Total current assets	61,063	25,466
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	1,195,831	531,121
Accumulated depletion	(166,592)	(57,529)
Total oil and gas properties, net	1,029,239	473,592
Other property and equipment, net	9,708	3,001
Total property and equipment, net	1,038,947	476,593
OTHER NONCURRENT ASSETS		
Unamortized debt issuance costs	3,273	1,503
Derivative instruments	26	—
Other assets	119	14,830
Total noncurrent assets	3,418	16,333
TOTAL ASSETS	$ 1,103,428	$ 518,392
LIABILITIES AND STOCKHOLDERS' / MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 382	$ 7,629
Accrued liabilities	132,311	39,225
Derivative instruments	41,782	9,567
Total current liabilities	174,475	56,421
LONG-TERM LIABILITIES		
Senior secured revolving credit facility	155,000	132,000
Derivative instruments	11,095	3,287
Asset retirement obligations	811	448
Deferred income taxes	57,943	—
Other long-term liabilities	4,759	124
Total long-term liabilities	229,608	135,859
Commitments and contingencies		
STOCKHOLDERS' / MEMBERS' EQUITY		
Members' equity	—	346,098
Preferred stock, $0.01 par value, 50,000,000 shares authorized, no shares issued at December 31, 2017; no shares authorized or issued at December 31, 2016	—	—
Common stock, $0.01 par value; 1,000,000,000 shares authorized, 212,930,655 shares issued at December 31, 2017; no shares authorized or issued at December 31, 2016	2,129	—
Additional paid-in capital	773,674	—
Accumulated deficit	(76,458)	(19,986)
Total stockholders' / members' equity	699,345	326,112
TOTAL LIABILITIES AND STOCKHOLDERS' / MEMBERS' EQUITY	$ 1,103,428	$ 518,392

The accompanying Notes are an integral part of these consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
REVENUES			
Oil sales	$ 241,788	$ 70,078	$ 31,534
Natural gas sales	9,065	2,213	948
NGL sales	15,571	3,068	1,329
Other operating revenues	888	1,163	40
Total revenues	267,312	76,522	33,851
OPERATING EXPENSES			
Lease operating expenses	17,874	7,505	3,165
Gathering and transportation expenses	4,424	1,046	171
Production and ad valorem taxes	16,120	4,345	2,244
Exploration	31	2,484	11
Depletion, depreciation, amortization and accretion	111,049	40,417	22,685
Impairment of unproved oil and natural gas properties	373	372	6,489
General and administrative expenses (including equity-based compensation of $442,976, $0 and $0 in 2017, 2016 and 2015, respectively)	466,067	11,690	7,446
Other operating expenses	247	649	250
Total operating expenses	616,185	68,508	42,461
INCOME (LOSS) FROM OPERATIONS	(348,873)	8,014	(8,610)
OTHER INCOME (EXPENSE)			
Gain (loss) on commodity derivatives	(42,615)	(15,145)	1,323
Interest expense, net	(2,861)	(2,629)	(197)
Other, net	358	—	—
Total other income (expense)	(45,118)	(17,774)	1,126
INCOME (LOSS) BEFORE INCOME TAX	(393,991)	(9,760)	(7,484)
Income tax expense (benefit)	57,943	—	—
NET INCOME (LOSS)	(451,934)	(9,760)	(7,484)
Less: Net loss attributable to Jagged Peak Energy LLC (predecessor)	(375,476)	(9,760)	(7,484)
NET INCOME (LOSS) ATTRIBUTABLE TO JAGGED PEAK ENERGY INC. STOCKHOLDERS	$ (76,458)	$ —	$ —
Net income (loss) attributable to Jagged Peak Energy Inc. Stockholders per common share:			
Basic	$ (0.36)		
Diluted	$ (0.36)		
Weighted-average common shares outstanding:			
Basic	212,932		
Diluted	212,932		

The accompanying Notes are an integral part of these consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENT OF CHANGES IN EQUITY
(in thousands)

	Members' Equity	Common Stock: Shares	Common Stock: Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity / Members' Equity
BALANCE AT DECEMBER 31, 2014	$ 243,556	$ —	$ —	$ —	$ (2,742)	$ 240,814
Capital contributions	51,000	—	—	—		51,000
Net income (loss)	—	—	—	—	(7,484)	(7,484)
BALANCE AT DECEMBER 31, 2015	294,556	—	—	—	(10,226)	284,330
Capital contributions	51,542	—	—	—	—	51,542
Net income (loss)	—	—	—	—	(9,760)	(9,760)
BALANCE AT DECEMBER 31, 2016	346,098	—	—	—	(19,986)	326,112
Deemed contribution - incentive unit compensation	364,314	—	—	—	—	364,314
Net income (loss) for the period prior to the corporate reorganization	—	—	—	—	(375,476)	(375,476)
Balance prior to corporate reorganization and initial public offering	710,412	—	—	—	(395,462)	314,950
Issuance of common stock in corporate reorganization	(710,412)	184,605	1,846	313,104	395,462	—
Issuance of common stock in initial public offering, net of offering costs	—	28,333	283	396,708	—	396,991
Equity-based compensation	—	—	—	63,950	—	63,950
Vested stock exchanged for tax withholding	—	(7)	—	(88)	—	(88)
Net income (loss)	—	—	—	—	(76,458)	(76,458)
BALANCE AT DECEMBER 31, 2017	$ —	212,931	$ 2,129	$ 773,674	$ (76,458)	$ 699,345

The accompanying Notes are an integral part of these consolidated and combined financial statements.

JAGGED PEAK ENERGY INC.
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ (451,934)	$ (9,760)	$ (7,484)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion expense	111,049	40,417	22,685
Management incentive unit advance	—	(14,712)	—
Impairment of unproved oil and natural gas properties	373	372	6,489
Exploratory dry hole costs	—	1,192	—
Amortization of debt issuance costs	606	260	61
Deferred income taxes	57,943	—	—
Equity-based compensation	442,976	—	—
(Gain) loss on commodity derivatives	42,615	15,145	(1,323)
Net cash receipts (payments) on settled derivatives	(2,618)	(2,292)	5,935
Other	882	(160)	(155)
Change in operating assets and liabilities:			
Accounts receivable and other current assets	(40,442)	(2,588)	(5,997)
Other assets	(3)	11	17
Accounts payable and accrued liabilities	17,424	4,198	144
Net cash provided by operating activities	178,871	32,083	20,372
CASH FLOWS FROM INVESTING ACTIVITIES			
Leasehold and acquisition costs	(73,492)	(54,681)	(13,716)
Development of oil and natural gas properties	(523,559)	(139,571)	(96,743)
Other capital expenditures	(2,983)	(1,969)	(213)
Proceeds from sale of oil and natural gas properties	—	796	440
Net cash used in investing activities	(600,034)	(195,425)	(110,232)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of common stock in initial public offering, net of underwriting fees	401,625	—	—
Proceeds from JPE LLC members	—	51,542	51,000
Proceeds from credit facility	165,000	112,000	20,000
Repayment of credit facility	(142,000)	—	—
Debt issuance costs	(2,362)	(1,220)	(603)
Costs relating to initial public offering	(3,216)	(1,418)	—
Employee tax withholding for settlement of equity compensation awards	(88)	—	—
Net cash provided by financing activities	418,959	160,904	70,397
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,204)	(2,438)	(19,463)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	11,727	14,165	33,628
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 9,523	$ 11,727	$ 14,165
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Interest paid, net of capitalized interest	$ 2,021	$ 2,190	$ 95
Cash paid for income taxes	—	—	—
SUPPLEMENTAL DISCLOSURE OF NONCASH INVESTING ACTIVITIES			
Accrued capital expenditures	$ 105,401	$ 36,581	$ 17,720
Asset retirement obligations	600	(100)	189
SUPPLEMENTAL DISCLOSURE OF NONCASH FINANCING ACTIVITIES			
Accrued offering costs	$ —	$ 1,224	$ —

The accompanying Notes are an integral part of these consolidated and combined financial statements.

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Jagged Peak Energy Inc. (either individually or together with its subsidiaries, as the context requires, "Jagged Peak" or the "Company") is an independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the southern Delaware Basin; the Delaware Basin is a sub-basin of the Permian Basin of West Texas. The Company's acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant oil-in-place within multiple stacked hydrocarbon-bearing formations.

Corporate Reorganization and Initial Public Offering

Jagged Peak is a Delaware corporation formed in September 2016, as a wholly owned subsidiary of Jagged Peak Energy LLC ("JPE LLC"), a Delaware limited liability company formed in April 2013. JPE LLC was formed by an affiliate of Quantum Energy Partners ("Quantum") and certain members of Jagged Peak's management team. Jagged Peak was formed to become the holding company of JPE LLC in connection with Jagged Peak's initial public offering (the "IPO").

Immediately prior to the IPO, all capital interests and management incentive units ("MIUs") in JPE LLC were converted into a single class of units which were then converted into common stock. Certain members of management and employees contributed a portion of common stock received upon the conversion of unvested or unallocated MIUs to JPE Management Holdings LLC, a limited liability company formed in connection with the IPO for the purpose of holding the unvested or unallocated common stock. Also immediately prior to the IPO, a corporate reorganization (the "corporate reorganization") took place whereby Jagged Peak, initially formed as a subsidiary of JPE LLC, formed JPE Merger Sub LLC as a subsidiary. JPE LLC merged into JPE Merger Sub LLC, with JPE LLC as the surviving entity. As a result, JPE LLC became a wholly owned subsidiary of Jagged Peak. Prior to the corporate reorganization, Quantum owned 98.6% of the membership interests of JPE LLC. Immediately following the corporate reorganization and IPO, Quantum owned 68.7% of the outstanding common stock of Jagged Peak. As all power and authority to control the core functions of Jagged Peak and JPE LLC were, and continue to be, controlled by Quantum, the corporate reorganization was treated as a reorganization of entities under common control and the results of JPE LLC have been consolidated and combined for all periods.

On January 27, 2017, the Company initiated its IPO of common stock to the public, and its common stock began trading on the New York Stock Exchange. During the IPO, the Company and selling stockholders sold 31,599,334 shares at $15.00 per share, raising $474.0 million of gross proceeds. Of the 31,599,334 shares issued to the public, 28,333,334 shares were sold by the Company, and 3,266,000 shares were sold by the selling stockholders. The gross proceeds of the IPO to the Company, based on the public offering price of $15.00 per share, were approximately $425.0 million, which resulted in net proceeds to the Company of $397.0 million after deducting expenses and underwriting discounts and commissions of approximately $28.0 million. The Company did not receive any proceeds from the sale of the shares by the selling stockholders. A portion of the proceeds from the IPO were used to repay the entire outstanding balance on JPE LLC's credit facility of $142.0 million as of the date the IPO proceeds were received. The remainder of the net proceeds from the IPO were used to fund a portion of the Company's 2017 capital expenditures program, and for other general corporate purposes.

Basis of Presentation

The accompanying consolidated and combined financial statements include the accounts of Jagged Peak and JPE LLC, and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). These consolidated and combined financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany and intra-company amounts have been eliminated. The consolidated and combined financial statements for periods prior to January 27, 2017 reflect the historical results of JPE LLC, other than the equity-based compensation expense and deferred tax expense, as further described in Notes 6 and 8, respectively.

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

Industry Segment and Geographic Information

The Company evaluated how it is organized and managed, and has identified one operating segment—the production and development of oil and natural gas. All of the Company's assets are located in the United States, and all of its revenues are attributable to customers located in the United States.

Note 2—Significant Accounting Policies and Related Matters

Use of Estimates

In the course of preparing the consolidated and combined financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Estimates made in preparing these consolidated and combined financial statements include, among other things, (1) estimates of oil and natural gas reserve quantities, which impact depreciation, depletion and amortization and impairment of oil and natural gas properties, (2) operating and capital costs accrued, (3) estimates of timing and costs used in calculating asset retirement obligations, (4) estimates of the fair value of equity-based compensation, (5) estimates used in developing fair value assumptions and estimates, (6) estimates of deferred income taxes and (7) estimates and assumptions used in the disclosure of commitments and contingencies. Changes in estimates, assumptions or actual results could have a significant impact on results in future periods.

Fair Value Measurements

The Company's financial instruments are measured at estimated fair value, and consist of derivative instruments, cash and cash equivalents, accounts payable and accrued expenses. The Company's derivative instruments are measured at fair value on a recurring basis. The carrying amounts of the Company's other financial instruments are considered to be representative of their fair market value due to their short-term nature.

The Company also applies fair value accounting guidance to measure nonfinancial assets and liabilities, such as the acquisition or impairment of oil and gas properties and the inception value of asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. See Note 4, *Fair Value Measurements*, for further discussion.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Company's cash balances held at commercial banks may at times exceed the Federal Deposit Insurance Corporation limit. The Company has not experienced any credit losses to date.

Revenue Recognition

Revenue is recognized when production is delivered to a purchaser at a fixed and/or determinable price, title has transferred and the collectability of the revenue is probable. Oil, natural gas and NGL revenue is recorded using the sales method. Under the sales method, revenues are based on actual sales volumes of commodities sold to purchasers. As of December 31, 2017 and 2016, the Company had no assets or liabilities recorded for oil, natural gas or NGL imbalances.

Accounts Receivable

The Company's accounts receivable are generated primarily from the sale of oil, natural gas and NGLs to various customers, from the billing of working interest partners for work on wells the Company operates, and from derivative settlements receivable shortly after the balance sheet date. The Company monitors the financial strength of its customers, partners, and counterparties. At December 31, 2017 and 2016, the Company did not have any reserves for doubtful accounts and did not incur any bad debt expense in any period presented.

At December 31, 2017 and 2016, accounts receivable was comprised of the following:

(in thousands)	December 31, 2017	December 31, 2016
Oil and gas sales	$ 42,869	$ 8,861
Joint interest	7,860	580
Other	5	886
Total accounts receivable	$ 50,734	$ 10,327

Significant Customers

The Company's share of oil, natural gas and NGL production is sold to a relatively small number of customers. The loss of any single purchaser could materially and adversely affect the Company's revenues in the short-term; however, the Company believes that the loss of any of its purchasers would not have a long-term material adverse effect on its financial condition and results of operations as oil and natural gas are fungible products with well-established markets and numerous purchasers.

The following purchasers individually accounted for 10% or more of the Company's total production revenue during the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31, 2017	2016	2015
Trafigura Trading, LLC	78%	57%	—%
Sunoco Partners Marketing	11%	31%	68%
Shell Trading (US) Company	—%	—%	21%

Other Current Assets

The components of other current assets are shown below:

(in thousands)	December 31, 2017	December 31, 2016
Prepaid expenses	$ 607	$ 255
Deferred offering costs	—	2,642
Other current assets	199	515
Total other current assets	$ 806	$ 3,412

Incremental costs directly related to the IPO were capitalized as deferred offering costs within other current assets until the IPO, at which point these costs were offset against the proceeds received.

Derivative Instruments

The Company uses commodity derivative instruments to manage its exposure to oil and natural gas price volatility. All of the commodity derivative instruments are utilized to manage price risk attributable to the Company's expected oil and natural gas production, and the Company does not enter into such instruments for speculative trading purposes. The Company does not designate any derivative instruments as hedges for accounting purposes. The Company records all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. The Company records gains and losses from the change in fair value of derivative instruments in current earnings as they occur. The Company currently does not utilize any derivative instruments to manage exposure to variable interest rates, but may do so in the future.

The cash flow impact of the Company's derivative activities is reflected as cash flows from operating activities. See Note 3, *Derivative Instruments*, for a more detailed discussion of the Company's derivative activities.

Oil and Natural Gas Properties

A summary of the Company's oil and natural gas properties, net is as follows:

	December 31,	
(in thousands)	**2017**	**2016**
Proved oil and natural gas properties	$ 1,012,321	$ 375,129
Unproved oil and natural gas properties	183,510	155,992
Total oil and natural gas properties	1,195,831	531,121
Less: Accumulated depletion	(166,592)	(57,529)
Total oil and natural gas properties, net	$ 1,029,239	$ 473,592

Proved Oil and Natural Gas Properties

The Company accounts for its oil and natural gas exploration and development costs using the successful efforts method. Under this method, all costs incurred related to the acquisition of oil and natural gas properties and the costs of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed when the well is determined not to have recoverable reserves in commercial quantities. Other items charged to expense generally include lease and well operating costs and delay rentals. Geological and geophysical costs directly related to developing proved properties are capitalized. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate.

Capitalized leasehold costs attributable to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. Capitalized well costs, including asset retirement costs, are depleted based on proved developed reserves on a field basis. For the years ended December 31, 2017, 2016 and 2015, the Company recorded depletion for oil and natural gas properties of $109.2 million, $39.4 million and $22.2 million, respectively. Depletion expense is included in depletion, depreciation, amortization and accretion expense on the accompanying consolidated and combined statements of operations.

Proved oil and natural gas properties are reviewed for impairment when facts and circumstances indicate their carrying value may not be recoverable. The Company estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to estimated fair value. The factors used to determine fair value may include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate. These assumptions and estimates represent Level 3 inputs, as further discussed in Note 4, *Fair Value Measurements*. The Company did not record any impairment expenses associated with its proved properties during the years ended December 31, 2017, 2016 and 2015.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties consist of costs to acquire undeveloped leases and unproved reserves, and are capitalized when incurred. When a successful well is drilled on an undeveloped leasehold or reserves are otherwise attributed to a property, unproved property costs are transferred to proved properties. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered.

Unproved properties are periodically assessed for impairment on a property-by-property basis. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage, and records impairment expense for any decline in value. Impairment of unproved properties for leases which have expired, or are expected to expire, was $0.4 million, $0.4 million and $6.5 million for the years ended December 31, 2017, 2016 and 2015, respectively. Additionally, during 2016 the Company incurred dry hole costs of $1.2 million related to a vertical test well drilled to an unproductive shallow horizon. There were no dry hole costs incurred in 2017 or 2015. Impairments are presented within impairment of unproved oil and natural gas properties, while dry hole costs are presented within exploration expenses on the consolidated and combined statements of operations.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the financial statements are estimated in accordance with the rules established by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB"). The Company's annual reserve estimates were prepared by third-party petroleum engineers. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash flows, future gross revenue, 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 reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates. See "Supplemental Oil and Natural Gas Disclosures (Unaudited)" following these Notes for a more detailed discussion of the Company's oil and natural gas reserves.

Other Property and Equipment

The following table presents the components of other property and equipment, net:

	December 31,	
(in thousands)	**2017**	**2016**
Other property and equipment	$ 12,167	$ 4,760
Less: Accumulated depreciation	(2,459)	(1,759)
Total other property and equipment, net	$ 9,708	$ 3,001

Other property and equipment includes equipment used in drilling and completion activities, the Company's field office, leasehold improvements, vehicles, IT hardware and software and office furniture, and is recorded at cost. Depreciation is recorded using the straight-line method over the estimated useful lives, which range from 2 to 20 years. Depreciation expense for the years ended December 31, 2017, 2016 and 2015 was $1.7 million, $0.9 million and $0.4 million, respectively. When property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounting records.

Unamortized Debt Issuance Costs

The Company incurred legal and bank fees in connection with obtaining its senior secured revolving credit facility and incurs such fees when increasing bank commitments in conjunction with redetermining an increase in its borrowing base. These costs are stated on the consolidated and combined balance sheets as noncurrent assets at cost, net of amortization, which is computed over the life of the credit facility using the straight-line method and recognized as interest expense on the consolidated and combined statements of operations.

Other Noncurrent Assets

At December 31, 2017, other noncurrent assets primarily consists of deposits for office space leases. At December 31, 2016, other noncurrent assets included a $14.7 million cash advance to management incentive unit advance recipients. The advance was recognized on the consolidated and combined statements of operations as equity-based compensation expense upon the IPO, which was considered a vesting event. See Note 6, *Equity-based Compensation*, for more information on the management incentive unit advance.

Accrued Liabilities

The components of accrued liabilities are shown below:

(in thousands)	December 31, 2017	December 31, 2016
Accrued capital expenditures	$ 102,956	$ 28,490
Accrued accounts payable	8,488	3,312
Royalties payable	6,105	2,653
Other current liabilities	14,762	4,770
Total accrued liabilities	$ 132,311	$ 39,225

Asset Retirement Obligations

The Company records a liability for the fair value of an asset retirement obligation ("ARO") related to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and restoration in accordance with local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized in proved oil and natural gas property costs as part of the carrying cost of the oil and natural gas asset, and depleted over the life of the asset. The recognition of the ARO requires management to make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements, credit-adjusted risk-free discount rates and inflation rates. Revisions to estimated ARO can result from changes in working interest, retirement cost estimates and estimated timing of abandonment. The ARO liability is accreted at the end of each period through charges to accretion expense, which is included in the statements of operations within depletion, depreciation, amortization and accretion expense.

Equity-based Compensation

The Company recognizes compensation cost related to equity-based awards granted to employees, members of the Company's board of directors and non-employee contractors in the financial statements based on their estimated grant-date fair value. The Company may grant various types of equity-based awards including stock options, stock appreciation rights, restricted stock, restricted stock units (including awards with service-based vesting and market condition-based vesting provisions), stock awards, dividend equivalents and other types of awards. Service-based restricted stock and units are valued using the market price of Jagged Peak's common stock on the grant date. The fair value of the market condition-based restricted stock units is based on the grant-date fair value of the award utilizing a Monte Carlo valuation model. Compensation cost is recognized ratably over the applicable vesting period, and is recognized in general and administrative expense on the consolidated and combined statements of operations. The Company has elected to account for forfeitures in compensation expense as they occur. Equity-based compensation arrangements to nonemployees are recognized as expense over the related service period and are subject to remeasurement at the end of each reporting period until they vest.

Income Taxes

Income taxes are accounted for under the asset and liability method. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts and income tax basis of assets and liabilities and the expected benefits of utilizing net operating losses, interest expense and tax credit carryforwards, using enacted tax rates in effect for the taxing jurisdiction in which the Company operates for the year in which those temporary differences are expected to be recovered or settled. Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The Company classifies all deferred tax assets and liabilities as noncurrent. The Company recognizes the financial statement effects of a tax position when it is more likely than not, based on technical merits, that the position will be sustained upon examination. The Company periodically assesses the realizability of its deferred tax assets by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available positive and negative evidence when determining whether a valuation allowance is required. In making this assessment, the Company evaluates possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences available and tax planning strategies. Deferred tax assets are then reduced by a valuation allowance if the Company believes it is more likely than not such deferred tax assets will not be realized.

The Company's accounting predecessor, JPE LLC, was treated as a partnership for federal and state income tax purposes. Accordingly, the accompanying consolidated and combined financial statements do not include a provision or liability for income taxes prior to the corporate reorganization.

Earnings per Share

The Company uses the treasury stock method to determine the potential dilutive effect of restricted stock units and performance stock units.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for the benefit of all employees at 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 for participating employees up to a certain percentage of the employee contributions. Matching contributions totaled approximately $0.5 million in the year ended December 31, 2017, and $0.2 million for each of the years ended December 31, 2016 and 2015. Benefits under this plan are available to all employees, and employees are fully vested in the employer contribution upon receipt.

Recent Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new guidance requires companies to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. In May 2016, the FASB issued ASU 2016-11, which rescinds the SEC accounting guidance regarding the use of the entitlements method for recognition of natural gas revenues. The standards can be adopted using either a full retrospective method or a modified retrospective method, as outlined in ASU 2014-09. The new standards became effective for the Company on January 1, 2018, and the Company has elected to adopt it using the modified retrospective method. The Company evaluated its existing contracts and determined it will not be required to record a cumulative effect adjustment as the new standards did not have a material impact compared to the Company's current use of the sales method, which is generally consistent with the new standards. The Company implemented the necessary changes to its business processes, systems and controls to support recognition and disclosure of this new standard. While the Company does not expect 2018 net income (loss) or cash flows from operations to be impacted by revenue recognition timing changes, there will be certain changes to the presentation of revenues and related expenses beginning January 1, 2018. If the new standard had been in effect for previous periods, all gathering and transportation expenses would have been included as a reduction to natural gas and NGL sales.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which requires all leases with a term greater than one year to be recognized on the balance sheet as right-of-use assets and lease liabilities. This ASU retains a distinction between finance and operating leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and cash flows. The Company will adopt the new standard on January 1, 2019, using the modified retrospective approach. The Company is in process of evaluating the impact of this new standard, which includes an analysis of existing contracts, including drilling rig and frac fleet contracts, office leases and certain field equipment. The Company is also evaluating the effect of ASU 2016-02 on its current accounting policies and disclosures. The Company believes that adopting the standard will result in increases to the assets and liabilities on its consolidated and combined balance sheets, and changes to the timing and presentation of certain operating expenses on its consolidated and combined statements of operations. The update does not apply to leases of mineral rights to explore for or use oil and natural gas. In January 2018, the FASB issued ASU 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*, which permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Company's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. The Company intends to elect this transition provision. The Company continues to monitor relevant industry guidance regarding the implementation of ASU 2016-02 and will adjust its implementation strategies as necessary.

In May 2017, the FASB issued ASU 2017-09, *Compensation-Stock Compensation (Topic 718) Scope of Modification Accounting*. The ASU clarifies which changes to the terms or conditions of an equity-based payment award require an entity to apply modification accounting in Topic 718. The standard became effective for the Company on January 1, 2018. The impact of this new standard will depend on the extent and nature of future changes to the terms of Company's equity-based payment awards.

Note 3—Derivative Instruments

The Company hedges a portion of its crude oil sales through derivative instruments to mitigate volatility in commodity prices. The use of these instruments exposes the Company to market basis differential risk if the WTI price does not move in parity with the Company's underlying sales of crude oil produced in the southern Delaware Basin. The Company also hedges a portion of its market basis differential risk through basis swap contracts.

The Company's derivative instruments are carried at fair value on the consolidated and combined balance sheets. The Company estimates the fair value using risk adjusted discounted cash flow calculations. Cash flows are based on published future commodity price curves for the underlying commodity as of the date of the estimate. Due to the volatility of commodity prices, the estimated fair values of the Company's derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. For more information, refer to Note 4, *Fair Value Measurements*.

Commodity Price Risk

The Company's principal market risks are its exposure to changes in oil, natural gas and NGL commodity prices. The prices of these commodities are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Company's control. The Company monitors these risks and enters into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on its business.

In an effort to reduce the variability of the Company's cash flows, the Company hedged the commodity prices associated with a portion of its expected future oil volumes by entering into swap and basis swap derivative financial instruments. With swaps, the Company typically receives an agreed upon fixed price for a specified notional quantity of oil or natural gas, and the Company pays the hedge counterparty a floating price for that same quantity based upon published index prices. Basis swap contracts establish the differential between Cushing WTI prices and Midland WTI prices, and represent the amount of reduction to Cushing, Oklahoma, prices for the notional volumes contracted. The Company's commodity derivatives may expose it to the risk of financial loss in certain circumstances. The Company's derivative arrangements provide protection on the hedged volumes if market prices decline below the prices at which these derivatives are set. If market prices rise above the prices at which the Company has hedged, the Company will be required to make settlement payments to its derivative counterparties.

The following table summarizes the Company's derivative contracts as of December 31, 2017:

Contract Period	Volumes (Bbls)	Wtd Avg Price ($/Bbl)
Oil Swaps[(1)]:		
First quarter 2018	1,315,250	$ 51.86
Second quarter 2018	1,275,500	$ 51.82
Third quarter 2018	1,343,200	$ 52.34
Fourth quarter 2018	1,329,400	$ 52.67
Total 2018	5,263,350	$ 52.18
Year ending December 31, 2019	2,372,500	$ 51.89
Oil Basis Swaps[(2)]:		
First quarter 2018	1,260,000	$ (1.08)
Second quarter 2018	1,274,000	$ (1.08)
Third quarter 2018	1,288,000	$ (1.08)
Fourth quarter 2018	1,288,000	$ (1.08)
Total 2018	5,110,000	$ (1.08)
Year ending December 31, 2019	2,920,000	$ (1.10)

(1) The index prices for the oil swaps are based on the NYMEX–WTI monthly average futures price.
(2) The oil basis swap differential price is between Cushing–WTI and Midland–WTI.

The Company has elected to not apply hedge accounting, and as a result, its earnings are affected by the use of the mark-to-market method of accounting for derivative financial instruments. The changes in fair value of these instruments are recognized through earnings as other income or expense rather than deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause noncash earnings volatility due to changes in the underlying commodity price indices. The ultimate gain or loss upon settlement of these transactions is recognized in earnings as other income or expense. Cash settlements of the Company's derivative contracts are included in cash flows from operating activities in the Company's statements of cash flows.

Subsequent to December 31, 2017, the Company entered into the following additional derivative contracts:

Contract Period	Volumes (Bbls)	Wtd Avg Price ($/Bbl)
Oil Swaps(1):		
First quarter 2018	88,500	$ 60.88
Second quarter 2018	136,500	$ 60.88
Third quarter 2018	138,000	$ 60.88
Fourth quarter 2018	138,000	$ 60.88
Total 2018	501,000	$ 60.88
Oil Basis Swaps(2):		
First quarter 2018	88,500	$ (0.03)
Second quarter 2018	136,500	$ (0.03)
Third quarter 2018	138,000	$ (0.03)
Fourth quarter 2018	138,000	$ (0.03)
Total 2018	501,000	$ (0.03)

(1) The index prices for the oil swaps are based on the NYMEX–WTI monthly average futures price.
(2) The oil basis swap differential price is between Cushing–WTI and Midland–WTI.

The Company recognized the following gains (losses) and net cash receipts (payments) in earnings for the years ended December 31, 2017, 2016 and 2015:

(in thousands)	2017	2016	2015
Gain (loss) on derivatives instruments, net	$ (42,615)	$ (15,145)	$ 1,323
Net cash receipts (payments) on settled derivatives	$ (2,618)	$ (2,292)	$ 5,935

The Company's derivative contracts are carried at their fair value on the Company's consolidated and combined balance sheets using Level 2 inputs, and are subject to industry standard master netting arrangements, which allow the Company to offset recognized asset and liability fair value amounts on contracts with the same counterparty. The Company's policy is to not offset these positions in its consolidated and combined balance sheets.

The following tables present the amounts and classifications of the Company's commodity contract derivative assets and liabilities as of December 31, 2017 and 2016 (in thousands):

As of December 31, 2017:	Balance Sheet Location	Gross amounts presented on the balance sheet	Netting adjustments not offset on the balance sheet	Net amounts
Assets				
Commodity contracts	Current assets - derivative instruments	$ —	$ —	$ —
Commodity contracts	Noncurrent assets - derivative instruments	26	(26)	—
Total assets		$ 26	$ (26)	$ —
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 41,782	$ —	$ 41,782
Commodity contracts	Noncurrent liabilities - derivative instruments	11,095	(26)	11,069
Total liabilities		$ 52,877	$ (26)	$ 52,851

As of December 31, 2016:	Balance Sheet Location	Gross amounts presented on the balance sheet	Netting adjustments not offset on the balance sheet	Net amounts
Liabilities				
Commodity contracts	Current liabilities - derivative instruments	$ 9,567	$ —	$ 9,567
Commodity contracts	Noncurrent liabilities - derivative instruments	3,287	—	3,287
Total liabilities		$ 12,854	$ —	$ 12,854

Derivative Counterparty Risk

Where the Company is exposed to credit risk in its financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement and monitors the appropriateness of these counterparties on an ongoing basis. Generally, the Company does not require collateral and does not anticipate nonperformance by its counterparties.

The Company's counterparty credit exposure related to commodity derivative instruments is represented by contracts with a net positive fair value at the reporting date. These outstanding instruments, if any, expose the Company to credit risk in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of the Company's counterparties decline, its ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third-party. In the event of a counterparty default, the Company may sustain a loss and its cash receipts could be negatively impacted.

At December 31, 2017, the Company had commodity derivative contracts with three counterparties, all of which were lenders or affiliates of lenders under the Company's Amended and Restated Credit Facility (as defined in Note 5, *Debt Obligations*) and all of which had investment grade credit ratings. These counterparties accounted for all the Company's counterparty credit exposure related to commodity derivative assets.

Note 4—Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Financial assets and liabilities are measured at fair value on a recurring basis. Nonfinancial assets and liabilities, such as the initial measurement of ARO liabilities and oil and natural gas properties upon acquisition or impairment, are recognized at fair value on a nonrecurring basis.

The Company categorizes the inputs to the fair value of its financial assets and liabilities using a three-tier fair value hierarchy, established by the FASB, that prioritizes the significant inputs used in measuring fair value:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry standard models that consider various assumptions, including quoted prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include nonexchange-traded derivatives such as over-the-counter forwards, swaps and options.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value, and the company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and liabilities measured on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. To determine the fair value at the end of each reporting period, the Company computes discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. The Company compares these prices to the price parameters contained in its hedge contracts to determine estimated future cash inflows or outflows, which are then discounted. The fair values of the Company's commodity derivative assets and liabilities include a measure of credit risk. These valuations are Level 2 inputs.

The following table is a listing of the Company's assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2017 and 2016:

	Level 2	
(in thousands)	**December 31, 2017**	**December 31, 2016**
Assets from commodity derivative contracts	$ 26	$ —
Liabilities due to commodity derivative contracts	$ 52,877	$ 12,854

Assets and liabilities measured on a nonrecurring basis

The Company applies the provisions of the fair value measurement standard on a nonrecurring basis to its nonfinancial assets and liabilities, such as the acquisition or impairment of proved and unproved oil and gas properties and the inception value of ARO liabilities. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations.

The Company reviews its proved oil and natural gas properties for impairment whenever facts and circumstances indicate their carrying value may not be recoverable. In such circumstances, the income approach is used to determine the fair value of proved oil and natural gas reserves. Under this approach, the Company estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to estimated fair value. The factors used to determine fair value may include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate. These assumptions and estimates represent Level 3 inputs. No impairments were recorded on proved properties during the years ended December 31, 2017, 2016 and 2015.

Unproved oil and natural gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of the unproved properties, the Company uses a market approach, and takes into account future development plans, remaining lease term, drilling results, and reservoir performance. The Company recorded impairment expense on unproved oil and gas properties of $0.4 million, $0.4 million and $6.5 million for the years ended December 31, 2017, 2016 and 2015, respectively. These impairments resulted from expirations of certain undeveloped leases.

The inception value and revision value, if any, of the Company's AROs are also measured at fair value on a nonrecurring basis. The inputs used to determine such fair value are based primarily on the present value of estimated future cash outflows. Given the unobservable nature of these inputs, they represent Level 3 inputs.

The fair value measurements of assets acquired and liabilities assumed in a business acquisition are measured on a nonrecurring basis on the acquisition date using an income valuation approach based on inputs that are unobservable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These inputs require significant judgments and estimates by the Company's management at the time of the valuation.

Fair Value of Other Financial Instruments

The Company has other financial instruments consisting primarily of cash and cash equivalents, accounts receivable, other current assets, accounts payable, and accrued liabilities that approximate fair value due to the nature of the instrument and the short-term maturities of these instruments.

Note 5—Debt Obligations

In June 2015, JPE LLC entered into a five-year senior secured revolving credit facility ("JPE LLC's Credit Facility"), with a maximum facility amount of $500.0 million. At December 31, 2016, JPE LLC's Credit Facility, as amended, had a borrowing base of $160.0 million, with $132.0 million outstanding under the credit facility, and $28.0 million in unused borrowing capacity. The weighted-average interest rate as of December 31, 2016 was 3.99%. During the year ended December 31, 2016, JPE LLC capitalized $0.1 million of interest. Following the IPO, the outstanding balance under JPE LLC's Credit Facility was paid in full.

In January 2017, JPE LLC's Credit Facility borrowing base was increased to $180.0 million.

In February 2017, the Company, as parent guarantor, and JPE LLC, as borrower, entered into an amended and restated credit facility with Wells Fargo Bank, N.A., as administrative agent and the lenders thereto (the "Amended and Restated Credit Facility"). The borrowing base remained at $180.0 million, while the maximum facility amount increased to $1.0 billion. Borrowings under the Amended and Restated Credit Facility bore interest at a rate elected by the Company that was equal to an alternative base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50%, and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranged from 1.25% to 2.25% in the case of the alternative base rate and from 2.25% to 3.25% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company paid a commitment fee of 0.50% per year on the unused portion of the borrowing base.

The Amended and Restated Credit Facility matures on February 1, 2022, and is subject to semiannual borrowing base redeterminations on or around April 1 and October 1 of each year. The borrowing base increased from $180.0 million to $250.0 million after the April 2017 redetermination.

In October 2017, the Company and JPE LLC entered into an amendment to the Amended and Restated Credit Facility ("Amendment No. 1"). Under Amendment No. 1, the borrowing base increased to $425.0 million and the pricing grid was lowered. Following Amendment No. 1, the Amended and Restated Credit Facility remains subject to semiannual borrowing base redeterminations on or around April 1 and October 1 of each year. Borrowings under the Amended and Restated Credit Facility following Amendment No. 1 bore interest at a rate elected by the Company that was equal to an alternative base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50%, and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranged from 1.00% to 2.00% in the case of the alternative base rate, and from 2.00% to 3.00% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company paid a commitment fee of 0.375% to 0.50% per year on the unused portion of the borrowing base, depending on the relative amount of the loan outstanding in relation to the borrowing base.

Amendment No. 1 is secured by oil and natural gas properties representing at least 90% of the value of the Company's proved reserves. Amendment No. 1 contains certain covenants, including among others, restrictions on indebtedness, restrictions on liens, restrictions on investments, restrictions on mergers, restrictions on sales of assets, restrictions on dividends and payments to the Company's capital interest holders and restrictions on the Company's hedging activity.

Amendment No. 1 contains financial covenants, which are measured on a quarterly basis. The covenants, as defined in the Amended and Restated Credit Agreement, include requirements to comply with the following financial ratios:

- a current ratio, which is the ratio of consolidated current assets (including unused commitments under the credit facility and excluding noncash assets related to ARO and derivatives) to consolidated current liabilities (excluding the current portion of long-term debt under the credit agreement and noncash liabilities related to ARO and derivatives), as of the last day of each fiscal quarter, of not less than 1.0 to 1.0; and
- a leverage ratio, which is the ratio of consolidated Debt (as defined in the credit agreement) as of the last day of each fiscal quarter, subject to certain exclusions (as described in the credit agreement) to EBITDAX (as defined in the credit agreement) for the last 12 months ending on the last day of that fiscal quarter, of not greater than 4.0 to 1.0.

As of December 31, 2017, the Company was in compliance with its financial covenants.

As of December 31, 2017, there was $155.0 million outstanding under Amendment No. 1 of the Amended and Restated Credit Facility. The weighted-average interest rate as of December 31, 2017 was 3.68%. During the year ended December 31, 2017, the Company capitalized $0.3 million of interest.

In March 2018, the Company entered into Amendment No. 2 to the Amended and Restated Credit Facility which extended the maturity date of the Amended and Restated Credit Facility to March 2023, increased the maximum facility amount to $1.5 billion, increased the borrowing base to $540.0 million, increased the hedging limits and lowered the pricing grid. Borrowings under the Amended and Restated Credit Facility following Amendment No. 2 bear interest at a rate elected by the Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the federal funds effective rate plus 0.50%, and the thirty-day adjusted LIBOR plus 1.0%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate, and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The commitment fee paid by the Company remains at 0.375% to 0.50% per year on the unused portion of the borrowing base, depending on the relative amount of the loan outstanding in relation to the borrowing base.

Note 6—Equity-based Compensation

In connection with the IPO, the Company adopted the Jagged Peak Energy Inc. 2017 Long Term Incentive Plan (the "Plan"), which allows the Company to grant up to 21,200,000 equity-based compensation shares to employees, consultants and directors of the Company and its affiliates who perform services for the Company. The Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, stock awards, dividend equivalents, performance awards and other types of awards. The terms and conditions of the awards granted are established by the Company's Board of Directors. Shares issued as a result of awards granted under the Plan are generally new common shares.

Equity-based compensation expense, which is recorded in general and administrative expense in the accompanying consolidated and combined statements of operations, was as follows for the periods indicated:

(in thousands)	Year Ended December 31, 2017	2016	2015
Incentive unit awards	$ 439,411	$ —	$ —
Restricted stock unit awards	1,616	—	—
Performance stock unit awards	1,497	—	—
Restricted stock unit awards issued to nonemployee directors	452	—	—
Total equity-based compensation expense	$ 442,976	$ —	$ —

Incentive Unit Awards

In connection with its formation in April 2013, JPE LLC established an incentive pool plan, whereby JPE LLC granted MIUs to employees and selected other participants. The MIUs were considered "profits interests" that participated in certain events whereupon distributions would be made to MIU holders (only after certain return thresholds were achieved by the capital interests) following a qualifying initial public offering, sale, merger, or other qualifying transaction involving the units or assets of JPE LLC ("Vesting Event").

The MIUs were accounted for under FASB ASC Topic 710, *Compensation–General*, which requires compensation expense for the MIUs to be recognized when all performance, market and service conditions are probable of being satisfied, which is generally upon a Vesting Event. As of and through December 31, 2016, the vesting of the MIUs was not deemed probable, therefore no expense was recognized through December 31, 2016.

The corporate reorganization provided a mechanism by which all capital interests and MIUs in JPE LLC were converted into a single class of units, which were then converted into the Company's common stock. A portion of these shares vested and a portion were transferred to JPE Management Holdings LLC ("Management Holdco") and became subject to the terms and conditions of the amended and restated JPE Management Holdings LLC limited liability company agreement (the "Management Holdco LLC Agreement"). As a result of the IPO, the satisfaction of all conditions relating to MIUs in JPE LLC held by the current and former officers and employees who owned equity interests in JPE LLC, was deemed probable. As a result, based on the Company's IPO price of $15.00 per share, compensation expense of $379.0 million was recognized for the vested shares of common stock at the IPO date, all of which was noncash except for $14.7 million related to a management incentive advance payment made in April 2016. The $14.7 million is included in the consolidated and combined statements of cash flows as an operating activity for the year ended 2016.

The shares of common stock transferred to Management Holdco are accounted for under ASC 718, *Compensation–Stock Compensation*, and generally vest over three years. During the year ended December 31, 2017, the Company recognized $60.4 million of equity-based compensation expense related to the shares held by Management Holdco. Included in the $60.4 million is $22.2 million of equity-based compensation related to awards held by Management Holdco which were modified in conjunction with a March 2017 separation agreement of a former executive officer. The remaining compensation expense of these awards will be recognized ratably according to the terms of the Management Holdco LLC Agreement. The equity-based compensation relative to these shares of common stock transferred to Management Holdco is not deductible for federal or state income tax purposes.

A summary of incentive unit award activity for the year ended December 31, 2017 is as follows:

	Incentive Units	Weighted Average Grant-date Fair Value
Unvested at Corporate Reorganization	9,570,280	$ 15.00
Granted	235,346	$ 12.45
Vested	(2,049,881)	$ 14.97
Forfeited	—	$ —
Unvested at December 31, 2017	7,755,745	$ 14.93
Compensation costs remaining at December 31, 2017 (in millions)	$ 80.6	
Weighted average remaining period at December 31, 2017 (in years)	2.1	

The total fair value of incentive units that vested from the IPO date to December 31, 2017 was $25.2 million.

At December 31, 2017, there were 431,321 of unallocated shares of Company common stock held at Management Holdco. When these shares are granted, they will be valued using the closing stock price on the date of grant, and the Company will recognize the related expense over the requisite service period.

In February 2018, certain employees notified the Company of their desire to terminate their employment. Under the terms of the Management Holdco LLC Agreement, upon voluntary termination of employment by an incentive unit award holder, the Board of Directors has the discretion to allow outstanding unvested incentive unit awards to immediately vest, to continue to vest post-termination, and/or to be automatically forfeited, or any combination thereof. Any forfeited incentive units are reallocated to the remaining incentive unit holders employed by the Company. In February 2018, the Board of Directors modified these employees' unvested incentive units to either immediately accelerate vesting, in the case of retiring employees, or continue to vest post-termination under the original vesting period. The Company determined that these are accounted for as modifications under ASC 718 in the first quarter of 2018. As a result of these modifications to the service requirements, the Company determined that, for accounting purposes under ASC 718, the incentive unit awards allocated at IPO no longer met the substantive service condition, and that any previously unrecognized equity-based compensation expense should be recognized immediately. The acceleration of all previously unrecognized equity-based compensation expense for incentive unit awards allocated at the time of the IPO will result in the recognition of approximately $71.2 million of noncash equity-based compensation expense in the first quarter of 2018. This accounting does not alter the legal service obligations under the Management Holdco LLC Agreement for remaining employees whose awards were not modified. Equity-based compensation expense recognition related to incentive unit awards that were unallocated at the time of the IPO is unaffected.

Restricted Stock Unit Awards

Restricted stock unit awards ("RSUs") vest subject to the satisfaction of service requirements. Expense related to each RSU award is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur through reversal of expense on awards that were forfeited during the period. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant.

A summary of RSU award activity for the year ended December 31, 2017 is as follows:

	RSUs	Weighted Average Grant-date Fair Value
Unvested at December 31, 2016	—	$ —
Granted	588,894	$ 12.45
Vested	—	$ —
Forfeited	(5,921)	$ 12.61
Unvested at December 31, 2017	582,973	$ 12.44
Compensation costs remaining at December 31, 2017 (in millions)	$ 5.2	
Weighted average remaining period at December 31, 2017 (in years)	2.2	

Of the 588,894 RSUs granted during 2017, nonemployee directors received 55,744 at a weighted average grant-date fair value of $12.46. The remaining compensation costs at December 31, 2017 for these nonemployee director RSUs was $0.2 million, with a weighted average remaining period of 0.4 years.

Performance Stock Unit Awards

During 2017, the Company granted performance stock unit awards ("PSUs") to certain of its officers, which vest based on continuous employment and satisfaction of a performance metric based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR of a peer group of companies over an approximate three-year performance period ending December 31, 2019. The number of shares which may ultimately be earned ranges from zero to 200% of the PSUs granted. Expense related to these PSUs is recognized on a straight-line basis over approximately three years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

A summary of PSU award activity for the year ended December 31, 2017 is as follows:

	PSUs	Weighted Average Grant-date Fair Value
Unvested at December 31, 2016	—	$ —
Granted	398,566	$ 16.32
Vested	—	$ —
Forfeited	—	$ —
Unvested at December 31, 2017	398,566	$ 16.32
Compensation costs remaining at December 31, 2017 (in millions)	$ 5.0	
Weighted average remaining period at December 31, 2017 (in years)	2.0	

The grant-date fair value of the PSUs was determined using a Monte Carlo simulation, which uses a probabilistic approach for estimating the fair value of the awards. The expected volatility was derived from a weighted combination of implied volatility and historical volatility. The risk-free interest rate was determined using the yield available for zero-coupon U.S. government issues with remaining terms corresponding to the service periods of the PSUs.

The following table presents information regarding the weighted average fair value for PSUs granted during the year ended December 31, 2017 and the assumptions used to determine the fair values:

	Year Ended December 31, 2017
Dividend yield	—%
Volatility	55.7%
Risk-free interest rate	1.34%
Weighted average fair value of awards granted	$ 16.32

Note 7—Earnings Per Share

Basic earnings per share ("EPS") is computed by dividing net earnings by the weighted average number of shares of common stock outstanding for the period. Diluted earnings per share is similarly computed, except that the denominator includes the effect, using the treasury stock method, of unvested RSUs and PSUs, if including such potential shares of common stock units is dilutive. The PSUs included in the calculation of diluted weighted average shares outstanding are based on the number of shares of common stock that would be issuable if the end of the reporting period was the end of the performance period required for the vesting of such PSU awards. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all awards is anti-dilutive.

For the year ended December 31, 2017, the Company's EPS calculation includes only the net loss for the period subsequent to the corporate reorganization and IPO, and omits income or loss prior to these events. In addition, the basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the period from January 27, 2017, to December 31, 2017.

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

(in thousands, except per share amounts)	From January 27, 2017, to December 31, 2017
Net income (loss) attributable to Jagged Peak Energy Inc. stockholders	$ (76,458)
Basic weighted average shares outstanding	212,932
Effect of dilutive securities:	
Restricted stock units	—
Performance stock units	—
Diluted weighted average shares outstanding	212,932
Net income (loss) per common share:	
Basic	$ (0.36)
Diluted	$ (0.36)

The following table presents amounts that have been excluded from the computation of diluted earnings per common share as their inclusion would be anti-dilutive:

(in thousands)	From January 27, 2017, to December 31, 2017
Weighted average number of outstanding equity awards excluded from diluted earnings per share calculation:(1)	
Restricted stock units	411
Performance stock units	523

(1) When the Company incurs a net loss, all outstanding equity awards are excluded from the calculation of diluted loss per common share because the inclusion of these awards would be anti-dilutive.

Note 8—Income Taxes

JPE LLC was organized as a limited liability company and treated as a pass-through entity for federal income tax purposes. As such, taxable income and any related tax credits were passed through to its members and included in their tax returns. Accordingly, provision for federal and state corporate income taxes has been made only for the operations of the Company from January 27, 2017 through December 31, 2017 in the accompanying consolidated and combined financial statements. Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. Upon the change in tax status as a result of the corporate reorganization, the Company established an $80.7 million provision for deferred income taxes, which was recognized as tax expense from continuing operations.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate to 21%, (ii) repeals the corporate alternative minimum tax, (iii) imposes new limitations on the utilization of net operating losses and eliminates their carryforward restrictions and (iv) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense. In addition, the Tax Act preserves deductibility of intangible drilling costs and provides for 100% bonus depreciation on tangible personal property expenditures through 2022. The bonus depreciation percentage is phased down from 100% beginning in 2023 to 0% for years after 2026. The Company recognizes the effects of changes in tax laws and rates on deferred tax assets and liabilities and the retroactive effects of changes in tax laws in the period in which the new legislation is enacted or signed into law.

The SEC issued rules that would allow for a measurement period of up to one year after the enactment date of the Tax Act to finalize the impact of the Tax Act on a company's financial statements. The Company has substantially completed the analysis of the Tax Act and does not expect a material change due to the transition impacts. Any changes that do arise due to changes in interpretations of the Tax Act, legislative action to address questions that arise because of the Tax Act, changes in accounting standards for income taxes or related interpretations in response to the Tax Act, or any updates or changes to estimates the Company has utilized to calculate the transition impacts will be disclosed in future periods as they arise.

The components of the Company's provision for income taxes are as follows:

(in thousands)	**Year Ended December 31, 2017**
Current income tax expense:	
Federal	$ —
State	—
	—
Deferred income tax expense:	
Federal	56,350
State	1,593
	57,943
Provision for income taxes	$ 57,943

A reconciliation of the income tax expense calculated at the federal statutory rate of 35% to the total income tax expense is as follows:

(in thousands)	**Year Ended December 31, 2017**
Income (loss) before income taxes	$ (393,991)
Less: loss before income taxes prior to corporate reorganization	(375,476)
Income (loss) before income taxes subsequent to corporate reorganization	$ (18,515)
Income tax expense (benefit) at the federal statutory rate	$ (6,480)
Income tax expense relating to change in tax status	80,704
Federal tax reform changes - 2017 Tax Act	(37,282)
State income taxes, net of federal benefit	199
Nondeductible equity-based compensation	20,781
Other permanent differences	21
Income tax expense (benefit)	$ 57,943
Effective tax rate	(14.7)%

Prior to the Company's change in tax status in January 2017, income taxes did not significantly impact the results of operations. The equity-based compensation related to shares of common stock transferred to Management Holdco is not deductible for federal or state income tax purposes. See Note 6, *Equity-based Compensation*, for more information on the shares of common stock transferred to Management Holdco.

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

(in thousands)	December 31, 2017
Deferred income tax assets:	
Commodity derivatives	$ 11,412
Equity-based compensation	928
Net operating loss carryforwards	16,093
Other	1,726
	30,159
Deferred income tax liabilities:	
Oil and natural gas properties	88,102
	88,102
Net deferred income tax assets (liabilities)	$ (57,943)

The Company had U.S. net operating losses of approximately $16.1 million, which expire in 2037. Deferred tax assets are reduced by a valuation allowance if the Company believes it is more likely than not such deferred tax assets will not be realized. The Company periodically assesses its deferred tax assets for realizability and, as a result of such assessment, determined as of December 31, 2017 sufficient evidence existed to indicate it is more likely than not that its deferred tax assets will be realized.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. That Company gives financial statement recognition to those tax provisions that it believes are more likely than not to be sustained upon examination by the Internal Revenue Service or other government agency. As of December 31, 2017, the Company did not have any accrued liability for unrecognized tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. At December 31, 2017, the Company has made no provisions for interest or penalties related to uncertain tax positions.

The Company files income tax returns in the U.S. federal jurisdiction, Texas and Colorado. There are currently no federal or state income tax examinations underway. The Company's U.S. federal income tax returns remain open to examination by the taxing authorities for tax years 2014 through 2017, and its Texas and Colorado tax returns remain open to examination for the years 2013 through 2017.

Note 9—Asset Retirement Obligations

The following table summarizes the changes in the carrying amount of the ARO liabilities for the years ended December 31, 2017 and 2016. Any ARO classified as current is included in accrued liabilities on the consolidated and combined balance sheets.

(in thousands)	2017	2016
Asset retirement obligations at January 1,	$ 448	$ 608
Liabilities incurred and assumed	590	138
Liability settlements and disposals	(190)	(127)
Revisions of estimated liabilities	9	(224)
Accretion	72	53
Asset retirement obligations at December 31,	929	448
Less current portion of asset retirement obligations	(118)	—
Long-term asset retirement obligations	$ 811	$ 448

In 2017 and 2016, the Company recognized revisions of estimated liabilities totaling $9 thousand and $0.2 million, respectively, which were due to changes in working interest and estimated abandonment timing and costs.

Note 10—Commitments and Contingencies

Commitments

The table below shows the Company's future minimum payments under noncancelable operating leases and other commitments as of December 31, 2017:

(in thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Operating leases[(1)]	$ 2,052	$ 1,490	$ 1,514	$ 1,535	$ 1,552	$ 8,962	$ 17,105
Service and purchase contracts[(2)]	2,380	1,287	1,285	750	—	—	5,702
Rig contracts	16,054	—	—	—	—	—	16,054
Frac fleet contracts	73,200	—	—	—	—	—	73,200
Total	$ 93,686	$ 2,777	$ 2,799	$ 2,285	$ 1,552	$ 8,962	$ 112,061

(1) Primarily relates to the lease of the Company's corporate offices.
(2) Primarily relates to a retail power sales agreement and seismic data gathering contract.

Office and equipment operating lease commitments

The Company leases office space in Denver, Colorado, and Midland, Texas. The Company's lease for its initial corporate office space in Denver expires in September 2018, and in December 2017 the Company moved into a new corporate office space. The Company's new corporate office lease in Denver expires in 2028. In connection with this lease, the Company received $4.7 million of lease incentives primarily related to tenant improvements, which is recorded within other long-term liabilities on the consolidated and combined balance sheets. The lease incentive liability is amortized on a straight-line basis as a reduction to rent expense over the lease term. The tenant improvements are depreciated over the shorter of the useful life of the asset or the life of the lease. The Company also leases certain office equipment under operating leases, which expire over the next five years.

Rent expense with respect to these lease commitments was approximately $0.9 million for the year ended December 31, 2017, and $0.6 million for each of the years ended December 31, 2016 and 2015.

In January 2018, the Company entered into a termination agreement on its initial corporate office lease, in which the Company agreed to a one-time termination fee of approximately $0.3 million. Including this fee, the 2018 operating lease commitment would be $1.8 million.

Drilling rig commitments

At December 31, 2017, the Company had six drilling rigs under contract. If the Company were to terminate these contracts at December 31, 2017, it would be required to pay early termination penalties of $7.5 million. In 2016 and 2015, the Company terminated one drilling rig in each year and incurred early termination charges of approximately $0.2 million and $0.3 million, respectively. These charges are reflected as other operating costs on the consolidated and combined statements of operations.

Frac fleet commitments

At December 31, 2017, the Company had three frac fleets under contract through December 31, 2018. The majority of the contracts allow for reassignment of the frac fleets to another operator if the Company were to terminate their services prior to the end of the contract, at which point the Company would not be required to pay termination fees. However, if the fleets were not able to be reassigned, the Company would be required to pay termination fees of $57.2 million as of December 31, 2017.

Contingencies

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters

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 both December 31, 2017 and 2016, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Note 11—Related Party Transactions

Quantum employs certain members of the Company's board of directors and had significant capital interests in JPE LLC. As of December 31, 2017, Quantum owns 68.7% of the Company's common stock.

Quantum owns a 41.5% interest in Oryx Midstream Services, LLC (together with Oryx Southern Delaware Holdings, LLC, "Oryx"). The Company has a 12-year crude oil gathering agreement with Oryx whereby Oryx provides midstream gathering services to the Company. Under that agreement, the Company has the right to designate, and has designated, a third-party shipper to market the Company's crude oil. In addition, the Company paid fees to Oryx for the purchase and maintenance of connecting equipment.

Quantum also owns a 60.9% interest in Phoenix Lease Services, LLC ("Phoenix"), and an indirect interest in Trident Water Services, LLC ("Trident"), a wholly owned subsidiary of Phoenix. The Company regularly leases frac tanks and other oil field equipment from Phoenix, and regularly uses water transfer services provided by Trident. The Company is under no obligation to use either provider, and both provide services only when selected as a vendor through the Company's normal bidding process.

The following table summarizes fees paid to Oryx, Phoenix and Trident for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Oryx via 3rd party shipper(1)	$ 10,058	$ 2,125	$ —
Oryx(2)	$ 798	$ 1,765	$ 425
Phoenix(3)	$ 366	$ 338	$ 361
Trident(3)	$ 236	$ 590	$ 1,041

(1) Transportation fees paid by the Company's third-party shipper to Oryx pursuant to the crude oil gathering agreement are netted against revenue as they are included in the net price paid by to the third-party shipper.
(2) Fees paid to Oryx for the purchase and installation of connecting equipment are capitalized to proved properties on the consolidated and combined balance sheets.
(3) Fees paid to Phoenix and Trident are capitalized to proved properties on the consolidated and combined balance sheets.

At December 31, 2017 and 2016, the Company had outstanding payables to these related parties of $1.8 million and $0.7 million, respectively.

Oil and Gas Exploration and Production Activities

The Company has only one reportable operating segment, which is oil and gas development, exploration and production in the United States. See the Company's accompanying consolidated and combined statements of operations for information about results of operations for oil and gas producing activities. The amounts shown include the Company's net working interests in all of its oil and gas properties.

Capitalized Costs Relating to Oil and Gas Producing Activities

Aggregate capitalized costs related to the Company's oil and natural gas producing activities at December 31, 2017 and 2016 were as follows:

	December 31,	
(in thousands)	**2017**	**2016**
Proved property	$ 1,012,321	$ 375,129
Unproved property	183,510	155,992
	1,195,831	531,121
Accumulated depletion, depreciation and amortization	(166,592)	(57,529)
Net capitalized costs	$ 1,029,239	$ 473,592

Costs Incurred for Oil and Gas Activities

Costs incurred for the Company's oil and natural gas activities for the years ended December 31, 2017, 2016 and 2015 were as follows:

	Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Acquisition costs:			
Proved property	$ —	$ 7,482	$ —
Unproved property	69,121	47,618	11,437
Development costs(1)	597,426	158,349	115,492
Exploration costs	31	1,673	852
Total costs incurred	$ 666,578	$ 215,122	$ 127,781

(1) Includes amounts related to estimated asset retirement costs of $0.6 million, $22 thousand and $0.2 million for the years ended December 31, 2017, 2016 and 2015, respectively. The increase to the Company's asset retirement estimate for the year ended December 31, 2017, as compared to 2016, is primarily due to the estimated abandonment costs on the 46.1 net wells that began producing during 2017.

Oil and Natural Gas Reserve Quantities

The Company's proved oil and natural gas reserves are all located in the United States, within the Delaware Basin, a sub-basin of the Permian Basin of West Texas. All of the estimates of the proved reserves at December 31, 2017, 2016 and 2015 are based on reports prepared by Ryder Scott Company, LP, the Company's independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e. costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. A variety of methodologies are used to determine the Company's proved reserve estimates. The primary methodologies used are decline curve analysis, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates across substantially all the Company's properties. Reserve estimates are inherently imprecise, and estimates of undeveloped locations are more imprecise than estimates of established proved producing locations. Accordingly, the Company's reserve estimates are expected to change as future information becomes available.

Supplemental Oil and Natural Gas Disclosures (Unaudited)

Proved oil and natural gas reserves were calculated based on the prices for oil and natural gas during the 12-month period before the reporting date, determined as the unweighted average of the first-day-of-the-month pricing. For oil and natural gas liquids volumes, the benchmark WTI posted price is adjusted for quality, transportation fees and regional price differentials. For gas volumes, the Henry Hub spot price is adjusted for energy content, transportation fees and regional price basis differentials. This average price is also used in calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows.

The following table summarizes the average adjusted product prices for 2017, 2016 and 2015:

	2017	2016	2015
Oil price per Bbl	$ 48.26	$ 39.33	$ 46.26
Natural gas price per Mcf	$ 2.59	$ 2.22	$ 2.36
NGL price per Bbl	$ 26.69	$ 15.48	$ 16.49

In addition, the SEC requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. The Company's development plans at December 31, 2017 related to scheduled drilling over the next five years are subject to many uncertainties and variables, including availability of capital, future oil and natural gas prices, cash flows from operations, future drilling costs, demand for oil and natural gas and other economic factors.

The following table sets forth information regarding the Company's estimated net total proved and proved developed oil and natural gas reserve quantities:

	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved reserves:				
Balance December 31, 2014	1,918	1,629	365	2,555
Extensions, discoveries and other additions	8,734	4,906	1,226	10,778
Revisions of previous estimates	559	26	(11)	552
Production	(718)	(404)	(89)	(874)
Balance December 31, 2015	10,493	6,157	1,491	13,011
Acquisitions of reserves	340	430	54	466
Extensions, discoveries and other additions	20,314	13,663	2,653	25,244
Revisions of previous estimates	1,035	353	56	1,149
Sales of reserves	(75)	(132)	(24)	(121)
Production	(1,701)	(952)	(194)	(2,054)
Balance December 31, 2016	30,406	19,519	4,036	37,695
Extensions, discoveries and other additions	41,172	33,790	5,015	51,819
Revisions of previous estimates	(1,542)	3,546	(8)	(960)
Production	(4,979)	(3,601)	(617)	(6,196)
Balance December 31, 2017	65,057	53,254	8,426	82,358
Proved developed reserves:				
December 31, 2015	4,848	2,547	621	5,894
December 31, 2016	11,916	6,566	1,491	14,501
December 31, 2017	29,325	25,496	4,166	37,739
Proved undeveloped reserves:				
December 31, 2015	5,645	3,610	870	7,117
December 31, 2016	18,490	12,953	2,545	23,194
December 31, 2017	35,732	27,758	4,260	44,619

2017 Activity. During 2017, the Company's estimated proved reserves increased by 44.7 MMBoe to 82.4 MMBoe, compared to 37.7 MMBoe at year end 2016. The increase in proved reserves during 2017 was largely due to 51.8 MMBoe added through extensions and discoveries, due to 46.1 net new wells that began producing in 2017 and adding 49 gross (45.0 net) PUD locations. The Company's revisions of previous estimates were primarily the result of 2.2 MMBoe of negative revisions related to higher operating costs, partially offset by positive revisions due to pricing (0.6 MMBoe) and technical revisions (0.6 MMBoe).

2016 Activity. During 2016, the Company's estimated proved reserves increased by 24.7 MMBoe to 37.7 MMBoe, compared to 13.0 MMBoe at year end 2015. The increase in proved reserves during 2016 was largely due to 25.2 MMBoe added through extensions and discoveries, due to new wells completed in 2016 and adding 25 gross (23.9 net) PUD locations.

2015 Activity. Estimated proved reserves at December 31, 2015 were 13.0 MMBoe, compared to 2.6 MMBoe at December 31, 2014. The increase in proved reserves during 2015 was primarily related to the Company's drilling activities. During 2015, the Company drilled and completed seven gross (6.4 net) wells and added nine gross (8.6 net) PUD locations, leading to a combined increase of 10.8 MMBoe of extensions and discoveries.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure is calculated in accordance with guidance provided by the FASB, and is computed by applying the adjusted 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference, including the reduced rate effective for years after 2017 due to the Tax Act.

The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. If reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized. Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions.

The 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves, and is prescribed by GAAP.

With regard to the future income taxes, the Company's predecessor was a limited liability company, therefore a pass through entity for tax purposes. The effect of future net income taxes has been excluded from the standardized measure of discounted future net cash flows for 2016 and 2015 as the Company's predecessor was not subject to federal income taxes. The Company's predecessor was, however, subject to the Texas franchise tax, which is an entity-level tax at a statutory rate of up to 1.0% of a portion of gross revenue apportioned to Texas.

The following table presents the standardized measure of discounted net cash flows related to proved oil and gas reserves as of December 31, 2017, 2016 and 2015:

(in thousands)	2017	2016	2015
Future cash inflows	$ 3,502,239	$ 1,301,702	$ 524,538
Future production costs	(1,136,692)	(382,999)	(146,779)
Future development costs	(579,060)	(278,229)	(90,661)
Future income tax expenses	(291,218)	(8,671)	(3,467)
Future net cash flows	1,495,269	631,803	283,631
10% annual discount	(723,397)	(360,857)	(151,910)
Standardized measure of discounted future net cash flows	$ 771,872	$ 270,946	$ 131,721

Supplemental Oil and Natural Gas Disclosures (Unaudited)

A summary of principal sources of changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2017, 2016 and 2015 is as follows:

(in thousands)	2017	2016	2015
Standardized measure of discounted future net cash flows, beginning of period	$ 270,946	$ 131,721	$ 64,866
Sales of oil and natural gas, net of production costs and taxes	(228,006)	(62,453)	(28,264)
Extensions, discoveries and improved recovery, less related costs	607,043	160,238	118,532
Revisions of previous quantity estimates	(9,177)	14,315	5,187
Net changes in prices and production costs	125,082	(36,752)	(41,264)
Previously estimated development costs incurred during the period	121,135	36,996	34
Changes in estimated future development costs	12,330	1,019	1,898
Accretion of discount	27,539	13,347	6,552
Acquisitions of reserves	—	3,373	—
Sales of reserves	—	(1,506)	—
Net change in taxes	(141,653)	(2,674)	(1,042)
Changes in timing and other	(13,367)	13,322	5,222
Standardized measure of discounted future net cash flows, end of period	$ 771,872	$ 270,946	$ 131,721

Supplemental Quarterly Financial Data (Unaudited)

The following tables provide selected quarterly financial data derived from the Company's consolidated and combined financial statements for the years ended December 31, 2017 and 2016 (in thousands, except per share data):

	Quarter			
2017	**First**	**Second**	**Third**	**Fourth**
Revenues	$ 39,388	$ 53,051	$ 70,451	$ 104,422
Operating expenses	432,403	48,763	60,168	74,851
Operating income (loss)	(393,015)	4,288	10,283	29,571
Net income (loss)	(465,881)	16,403	(15,219)	12,763
Less: Net loss attributable to Jagged Peak Energy LLC (predecessor)	(375,476)	—	—	—
Net income (loss) attributable to Jagged Peak Energy Inc. Stockholders	$ (90,405)	$ 16,403	$ (15,219)	$ 12,763
Earnings per common share(1)				
Basic	$ (0.42)	$ 0.08	$ (0.07)	$ 0.06
Diluted	$ (0.42)	$ 0.08	$ (0.07)	$ 0.06

(1) The Company's EPS calculation for the first quarter of 2017 includes only the net loss for the period subsequent to the corporate reorganization and IPO, and omits income or loss prior to these events. In addition, the basic weighted average shares outstanding that were used in the calculation of the first quarter 2017 EPS calculation is based on the actual days in which the shares were outstanding for the period from January 27, 2017, to March 31, 2017. See Note 7, *Earnings per Share*, for more details.

Net income (loss) for each respective quarter include the following items:

First-quarter 2017:

- $379.0 million charge to equity-based compensation related to management incentive units in JPE LLC that vested at the time of the IPO (see Note 1, *Organization, Operations and Basis of Presentation*, and Note 6, *Equity-based Compensation*).
- $79.1 million income tax expense related to a change in tax status resulting from the corporate reorganization, which occurred in connection with the IPO (see Note 1, *Organization, Operations and Basis of Presentation*, and Note 8, *Income Taxes*).

Fourth-quarter 2017:

- $58.5 million net loss related to derivative instruments (see Note 3, *Derivative Instruments*).
- $37.3 million income tax benefit related to the impact of new income tax legislation (see Note 8, *Income Taxes*).

	Quarter			
2016	**First**	**Second**	**Third**	**Fourth**
Revenues	$ 10,245	$ 19,336	$ 22,064	$ 24,877
Operating expenses	16,403	15,729	17,623	18,753
Operating income (loss)	(6,158)	3,607	4,441	6,124
Net income (loss)	$ (7,450)	$ (5,749)	$ 5,410	$ (1,971)

Board of Directors

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Chairman

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James J. Kleckner

Michael C. Linn

John R. "J.R." Sult

S. Wil VanLoh, Jr.

Dheeraj "D" Verma

Blake A. Webster

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Chief Executive Officer & President

Robert W. Howard
Executive Vice President & Chief Financial Officer

Craig R. Walters
Executive Vice President & Chief Operating Officer

Christopher I. Humber
Executive Vice President, General Counsel & Secretary

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John G. Roesink
Vice President, Development Planning & Geoscience

Shonn D. Stahlecker
Controller

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Securities

Common Stock traded on NYSE, Symbol: JAG

Annual Meeting of Shareholders

May 22, 2018 at 8:00 a.m. Mountain Time at the Company's corporate office located at 1401 Lawrence Street, Suite 1800, Denver, Colorado 80202

SEC Form 10-K

The Company's 2017 annual report to the Securities and Exchange Commission on Form 10-K is available without charge upon request to the Company's Denver office. This report is prepared for the information of security holders, employees and other interested persons. It is not transmitted in connection with the sale of any security or offer to sell or buy any security.

Web Site

Information about Jagged Peak Energy Inc., including an archive of news releases, access to SEC filings, and documents relating to corporate governance, is available from the Company's website at www.jaggedpeakenergy.com.

CEO and CFO Certification

On March 23, 2018, the Company's Chief Executive Officer submitted to the New York Stock Exchange ("NYSE") the annual certification required by Section 801(a) and 801(c) of the NYSE listing standards. In addition, the Company filed with the Securities and Exchange Commission exhibits to its Annual Report on Form 10-K for the year ended 2017, the certifications, required pursuant to Section 302 of the Sarbanes-Oxley Act, of its Chief Executive Officer and Chief Financial Officer relating to the quality of its public disclosure.

Jagged Peak Energy

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