2016 ANNUAL REPORT

DEVELOPING A BRIGHT FUTURE

EXTRACTION
Oil & Gas

NASDAQ: XOG

Extraction Oil & Gas, Inc.
is a domestic energy company based in Denver, Colorado. Our Company focuses on the exploration and production of oil and gas reserves, and is committed to safe and responsible operations in the Denver-Julesburg Basin.

Founded in December 2012,
Extraction Oil & Gas has an experienced technical team with decades of combined experience in horizontal drilling and completion operations. Our growth strategy includes high-quality acreage acquisitions and forming strategic joint ventures with select operators in the Greater Wattenberg Field.

LETTER TO OUR SHAREHOLDERS

Ring the Bell. *On October 12, Extraction Oil & Gas debuted on the NASDAQ trading under the symbol XOG. An impressive 33.3 million shares were sold on the first day of trading.*

Dear Fellow Shareholders:

From its 2012 inception, we envisioned Extraction Oil & Gas as an industry leader. As we reflect on recent achievements, our aspirations continue to broaden.

Despite a challenging commodity price environment, 2016 was one of extraordinary growth and transformation. While growing its production 57 percent, Extraction debuted on NASDAQ under the symbol XOG. Along the way we made significant progress in building out our organization, adding top-tier talent to execute our ambitious goals. We finished the year strong, and we are extremely pleased with our current outlook.

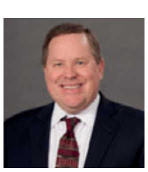
We have implemented industry-leading technologies and best management practices that reinforce our commitment to safety, environmental stewardship, and community partnership. Innovative technologies, like our use of electric-powered rigs, enable us to minimize inconveniences to our neighbors while maintaining the natural beauty of the communities in which we live and operate.

"Our strong financial standing and high-quality asset base position us positively within the industry."

Our drilling and completion operations are on schedule, and we are on track to exceed our 2016 performance, forecasting approximately 70 percent production growth. Extraction entered 2017 with zero net debt, some $589 million cash, and almost $1.1 billion of total liquidity. Our strong financial standing and high-quality asset base position us positively within the industry. Executing our aggressive capital program while maintaining our healthy balance sheet remain our top priorities as we continue to focus on creating long-term shareholder value.

Extraction has come a long way these past four years. We thank you for your ongoing support while we work to develop a bright and sustainable future.

Sincerely,



Mark Erickson
Chairman of the Board
Chief Executive Officer

March 28, 2017

2016 HIGHLIGHTS

500,000

TOTAL OPERATING HOURS WITHOUT A LOST-TIME INCIDENT

ZERO
INCIDENTS IN 2016

935,000
AVERAGE FEET DRILLED PER NET RIG

AN INCREASE OF 71% FROM 2015

57%
INCREASE IN PRODUCTION

40%
DECREASE IN GENERAL AND ADMINISTRATIVE COSTS PER BARREL OF OIL EQUIVALENT

FORM 10-K FINANCIALS

FORM 10-K
FINANCIALS

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, 2016

OR

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

For the transition period from ____________ to ____________

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street, Suite 5300 **Denver, Colorado**	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 557-8300
(Registrant's telephone number, including area code)

Title of each class	Name of exchange on which registered
Common Stock, par value $0.01	**NASDAQ Global Select Market**

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 of 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 website, 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of June 30, 2016, the last business day of the registrant's most recently completed second quarter, the registrant's equity was not listed on a domestic exchange or over-the-counter market. The registrant's common stock began trading on the NASDAQ Global Select Market October 12, 2016.

The total number of shares of common stock, par value $0.01 per share, outstanding as of March 13, 2017 was 171,834,605.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2017 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

EXTRACTION OIL & GAS, INC.
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the Securities and Exchange Commission for further information on risk and uncertainties that could affect our business, financial condition, results of operations and cash flows. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- hazardous, risky drilling operations, including those associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;

- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- changes in tax laws;
- effects of competition; and
- seasonal weather conditions.

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

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Annual Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this report to the "Company," “Extraction,” "us," "we," "our," or "ours" or like terms refer to Extraction Oil & Gas, Inc. following the completion of our initial public offering on October 17, 2016, as described under Note 9 — Members’ and Stockholders’ Equity. When used in the historical context, the "Company," “Holdings,” "us," "we," "our" and "ours" or like terms refer to Extraction Oil & Gas Holdings, LLC and its subsidiaries. Holdings is our accounting predecessor, for which we present the consolidated financial statements in this Annual Report.

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

"Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

“Bbl/d” means Bbl per day.

“Btu” means on British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"BBtu" One billion Btus.

"BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"BOE/d" means BOE per day.

"CIG" means Colorado Interstate Gas.

"Completion" means the installation of permanent equipment for the production of oil or natural gas.

“Developed acreage” means the number of acres that are allocated or assignable to producing wells or wells capable of production.

“Development well” means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

"Field" means 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.

“Fracturing” or “hydraulic fracturing” means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases 1 permeability and porosity.

"Gas" or "Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"Gross Acres" or "Gross Wells" means the total acres or wells, as the case may be, in which we have a working interest.

“Henry Hub” means Henry Hub index. Natural gas distribution point where prices are set for natural gas futures contracts traded on the NYMEX.

"Horizontal drilling" or “horizontal well” means a wellbore that is drilled laterally.

"Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

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

"MBoe" One thousand barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

"MMBtu" One million Btus.

"MMcf" is an abbreviation for "1,000,000 cubic feet," which is a unit of measurement of volume for natural gas.

"Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development, or maintenance.

"Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"Play" means a regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in their area extent. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs.

"Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

"Productive well" means a well that is producing oil or natural gas or that is capable of production.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves" means those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"Proved undeveloped reserves" means 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 specific circumstances justify a longer time. Under no circumstances shall estimates of 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.

"PV-10 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

"Reasonable certainty" means a high degree of confidence that the reserves quantities will be recovered, when a deterministic method is used. A high degree of confidence exists if the reserves quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

"Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

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

"Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

"Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"SEC" means the Securities and Exchange Commission.

"SEC pricing" means the price per Bbl for oil or per MMBtu for natural gas as calculated from the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months, as adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

"Seismic data" means an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation.

"Spacing" means 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.

"Undeveloped acreage" means lease acres 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 or not such acreage contains proved reserves.

"Undeveloped leasehold acreage" means the leased 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 estimated net proved reserves.

"Unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Wattenberg Field" means the Greater Wattenberg Area within the Denver-Julesburg Basin of Colorado as defined by the Colorado Oil and Gas Conservation Commission, which are the lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, Six Principal Median.

"Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"WTI" means the price of West Texas Intermediate oil on the NYMEX.

PART I

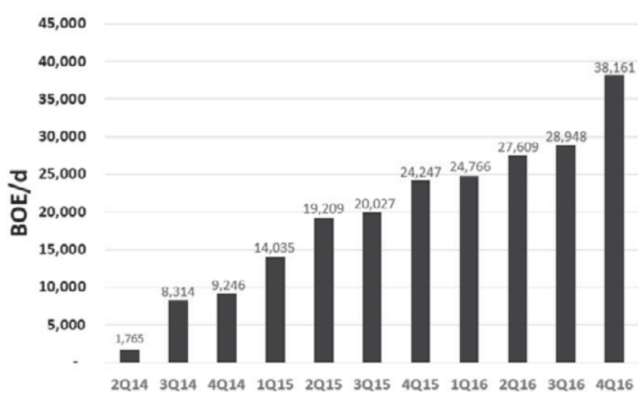
ITEMS 1. and 2. BUSINESS AND PROPERTIES

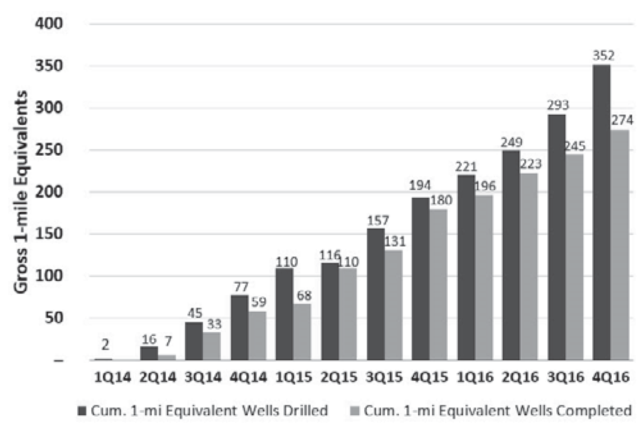
Company Overview

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado. The Wattenberg Field has been producing since the 1970s and is a premier North American oil and natural gas basin characterized by high recoveries relative to drilling and completion costs, high initial production rates, long reserve life and multiple stacked producing horizons. We have assembled, as of December 31, 2016, approximately 109,400 net acres of large, contiguous acreage blocks in some of the most productive areas of the DJ Basin, indicated by the results of our horizontal drilling program and the results of offset operators, which we refer to as the “Core DJ Basin”. Subsequent to year-end 2016, the Company acquired approximately 5,300 additional net acres and entered into agreements to acquire approximately 1,100 additional net acres in the Core DJ Basin. These properties have extensive production histories, high drilling success rates, and significant horizontal development potential. We believe our acreage in the Core DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our inventory is relatively low-risk, repeatable and will continue to generate economic returns. We are primarily focused on growing our proved reserves and production primarily through the development of our large inventory of identified liquids-rich horizontal drilling locations in the DJ Basin.

We were founded in November 2012 with the objective of becoming a Wattenberg focused company with acreage that has (i) low development risk as a result of being within the vicinity of other successful wells drilled by other oil and gas companies, (ii) limited vertical well drainage relative to offset operators in a field with significant historical vertical activity, and (iii) higher oil content than was traditionally targeted when many operators first established their position in the field seeking natural gas production. We believe these characteristics enhance our horizontal production capabilities, recoveries and economic results. Our drilling economics are further enhanced by our ability to drill longer laterals due to our large contiguous acreage position, which our management team built through organic leasing and a series of strategic acquisitions. We operated 96% of our horizontal production for the year ended December 31, 2016 and maintain control of a large majority of our drilling inventory. In addition, we proactively seek to secure the necessary midstream and operational infrastructure to keep pace with our production growth.

As of December 31, 2016, we have drilled 352 gross one-mile equivalent horizontal wells and have completed 274 gross one-mile equivalent horizontal wells. We are currently running a full time three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program. Our estimated average net daily production during the quarter and year ended December 31, 2016 was approximately 38,161 BOE/d and 29,891 BOE/d, respectively. The charts below demonstrate the substantial growth in our average net daily production and well count since the second quarter of 2014.





The following table provides summary information regarding our proved reserves as of December 31, 2016, and our estimated average net daily production during the year ended December 31, 2016.

Estimated Total Proved Reserves							Average Net Production	
Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	Total (MBoe)	% Oil	% Liquids(2)	% Developed	(BOE/d) (1)(3)	R/P Ratio (Years)(4)
90,995	507,735	62,448	238,066	38 %	64 %	20 %	29,891	21.8

(1) Includes de minimis reserves and production attributable to properties in our Other Rockies Area. Please see "—Other Properties."
(2) Includes both oil and NGL.
(3) Estimated average net daily production. Consisted of approximately 48% oil, 31% natural gas and 21% NGL.
(4) Represents the number of years proved reserves would last assuming production continued at the average rate for the year ended December 31, 2016. Because production rates naturally decline over time, the R/P Ratio is not a useful estimate of how long properties should economically produce.

The following table presents information regarding our horizontal drilling locations on a one-mile equivalent basis as of December 31, 2016. We have not booked proved reserves on all of these drilling locations.

	Identified Horizontal Drilling Locations(1)(2)(3)		
	Niobrara	Codell	Total
Gross	2,532	1,397	3,929
Net	1,657	917	2,574

(1) As adjusted for lateral length to present one-mile equivalents (approximately 4,200 feet). Please see "Business—Drilling Locations" for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, takeaway capacity, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in the addition of proved reserves to our existing proved reserves base.
(2) Does not include gross locations in the Other Rockies Area (as defined below) or acquisitions subsequent to 2016.
(3) Includes 92 drilled but uncompleted one-mile equivalent gross wells as of December 31, 2016.

Our Properties

Core DJ Basin, Focused in the Wattenberg Field

Our current operations are located in the DJ Basin, primarily in the Wattenberg Field where we target the oil and liquids-weighted Niobrara and Codell formations. As of December 31, 2016, our position in the Core DJ Basin consisted of approximately 109,400 net acres.

Our estimated proved reserves at December 31, 2016 were 238.1 MMBoe. As of December 31, 2016, we had a total of 1,014 gross producing wells, of which 345 were horizontal wells. The vertical wells we operate primarily serve to hold leases until we can drill more efficient horizontal wells on acreage we lease. Therefore, production from vertical wells does not represent a material amount of our current production and is anticipated to decline as a percentage of total production in the future as we drill more horizontal wells. Our estimated average net daily production during the year ended December 31, 2016 was approximately 29,891 BOE/d. Our working interest for all producing wells averages approximately 73% and our net revenue interest is approximately 58%.

We continue to expand our proved reserves in this area by drilling non-proved horizontal locations. As of December 31, 2016, we had an identified drilling inventory of approximately 730 gross (369 net) proved undeveloped horizontal drilling locations with varying lateral lengths on our acreage with average gross well costs of $4.2 million ($2.5 million normalized to 4,200 foot lateral length). During 2016, we drilled 103 gross operated horizontal wells and completed 72 gross operated horizontal wells.

Other Properties

We hold approximately 113,700 net acres outside of the Core DJ Basin, which we refer to as our "Other Rockies Area," that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. As of December 31, 2016, there were de minimis proved reserves associated with this acreage. Average daily production associated with these properties for the year ended December 31, 2016 was approximately 551 BOE/d. We have not identified any drilling locations at this time on our Other Rockies Area.

2017 Capital Budget

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million to non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Recent Developments

Recent Acquisitions

November 2016 Acquisition

On November 22, 2016, we acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the Core DJ Basin for approximately $120.0 million, including customary closing adjustments. The Company also made an additional $41.1 million deposit in November 2016 in conjunction with November 2016 Acquisition, which has been reflected in the December 31, 2016 consolidated balance sheet within the cash held in escrow line item. The deposit was made for two additional closings of leaseholds located in the Core DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres. The second closing is expected to occur in the first half of 2017 and will add approximately 800 net acres.

October 2016 Acquisition

On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field for total consideration of $405.3 million in cash, subject to customary purchase price adjustments (the "Bayswater Acquisition" or "October 2016 Acquisition"). Upon completion of the Bayswater Acquisition, we acquired producing and non-producing assets primarily located in the central and northwest portions of the Wattenberg Field from an existing working interest partner, primarily around our existing Greeley and Windsor areas. The Bayswater Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The Bayswater acquisition provided net daily production of approximately 6,900 BOE/d during the fourth quarter of 2016. We funded the purchase price through the issuance of $260.3 million in convertible preferred securities and borrowings under our revolving credit facility.

Option to Acquire Additional Assets from October 2016 Acquisition

In connection with the consummation of the Bayswater Acquisition, we paid $10.0 million for an option to purchase additional assets from Bayswater for an additional $190.0 million, for a total purchase price of $200.0 million (the "Additional Bayswater Assets"). The option allowed us to exercise at any time until March 31, 2017. If we were to not exercise our option to acquire the Additional Bayswater Assets, Bayswater would have the right until April 30, 2017 to elect to sell those assets to us for an additional $120.0 million, for a total purchase price for the Additional Bayswater Assets of $130.0 million. In March 2017, we entered into an amendment to this agreement with Bayswater to terminate both our and Bayswater's options for no further consideration. The $10.0 million was expensed in the fourth quarter of 2016 to other operating expenses within our consolidated statements of operations.

August 2016 Acquisition

On August 23, 2016, we acquired an unaffiliated oil and gas company's interests in approximately 1,100 net acres of leasehold located the Core DJ Basin for approximately $13.7 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date on August 23, 2016. We expect to close on approximately 300 additional net acres related to this acquisition in the first half of 2017 for an additional $3.4 million.

Capital Raises and Corporate Reorganization

Private Placement of Common Stock

On December 15, 2016, we issued approximately 25.0 million shares of common stock, at a price of $18.25 per share, in a private placement of our common stock (the "Private Placement"). The Private Placement resulted in approximately $457.0 million of gross proceeds and approximately $441.9 million of net proceeds (after deducting placement agent commission and offering expenses). The offering of the common stock issued in connection with the Private Placement was registered in a Form S-1, filed on January 9, 2017. Proceeds from the Private Placement are going to be used for general corporate purposes, including to fund the Company's 2017 capital expenditures.

Initial Public Offering

On October 17, 2016, we completed an initial public offering ("IPO") of approximately 33.3 million shares of our common stock at a price to the public of $19.00 per share and we became a publicly traded company listed on the NASDAQ Global Select Market ("NASDAQ") under the ticker symbol "XOG". After deducting underwriting discounts and commissions and estimated offering expenses payable by us, we received approximately $681.0 million of aggregate net proceeds from our IPO after the underwriters exercised their option on October 24, 2016 to purchase 5.0 million additional shares in full. We used (i) $90.0 million of the net proceeds from the Offering to redeem in full the Series A Preferred Units (as defined below) and (ii) $291.6 million to repay borrowings under our revolving credit facility. We intend to use the remaining net proceeds for general corporate purposes, including to fund our 2017 capital expenditures.

Corporate Reorganization

Extraction Oil & Gas, Inc., formerly known as Extraction Oil & Gas, LLC was converted from a Delaware limited liability company to a Delaware corporation, on October 12, 2016. In connection with the IPO on October 17, 2016, Extraction Oil & Gas Holdings, LLC ("Holdings") was merged with and into Extraction, and Extraction was the surviving entity to the merger (the "Corporate Reorganization"). All equity holders in Holdings, other than the holders of the Series B Preferred Units (which were converted in connection with the closing of the IPO into shares of Series A Preferred Stock), but including the holders of restricted units and incentive units, received approximately 108.5 million shares of our common stock, with the allocation of such shares among our existing equity holders determined, pursuant to the terms of the limited liability company agreement of Holdings, by reference to an implied valuation based on the 10-day volume weighted average price of Extraction's common stock following the closing of the IPO. The merger was treated as a reorganization of entities under common control. As part of Holdings' merger with and into Extraction, all of Holdings' other subsidiaries became direct or indirect subsidiaries of Extraction.

Convertible Preferred Securities

We previously issued to affiliates of Apollo Capital Management ("Apollo") $75.0 million in Series A Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. In connection with the consummation of the IPO, we used $90.0 million of the net proceeds to redeem the Series A Preferred Units in full, which included a premium of $15.0 million.

In addition, we have issued to, among others, investment funds affiliated with OZ Management LP and Yorktown Partners LLC (“Yorktown”) $185.3 million in Series B Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and we had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units were converted in connection with the closing of the IPO into shares of our Series A Preferred Stock that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). Beginning on or after the later of (a) 90 days after the closing of the IPO and (b) the earlier of 120 days after the closing of the IPO and the expiration of the lock-up period contained in the underwriting agreement entered into in connection with the IPO (the "Lock-Up Period End Date"), the Series A Preferred Stock will be convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the IPO, we may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference.

Amendment to Revolving Credit Facility

On December 7, 2016, the borrowing base of our revolving credit facility was increased from $450.0 million to $475.0 million. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Revolving Credit Facility.”

Drilling Locations

As of December 31, 2016, we have identified a total of 3,929 gross identified drilling locations as adjusted to one-mile equivalents. Our target horizontal location count implies lateral lengths of 4,200 feet per well. Approximately 31% of our gross identified drilling locations are attributable to proved undeveloped reserves. Our identified drilling locations have been identified based on our review of structure as well as production data from offsetting wells. We have internally generated this production data based on our evaluation of an extensive geological and engineering database. Information incorporated into this process includes both our own proprietary information as well as publicly available industry data. Specifically, open hole logging data, production statistics from operated and non-operated wells, and petrophysical data from cores taken from wellbores has provided the technical basis from which we identified the potential locations. This data have allowed us to determine areas for each reservoir that may produce commercial quantities of hydrocarbons and the viability of the potential locations.

Oil, Natural Gas and NGL Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates as of December 31, 2016, 2015 and 2014 were prepared based on a report by Ryder Scott, our independent petroleum engineers. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott summary reserve reports incorporated herein is Richard Marshall. Mr. Marshall has been practicing consulting petroleum engineering at Ryder Scott since 1981. Mr. Marshall is a registered Professional Engineer in the State of Colorado and has over 30 years of practical experience in the estimation and evaluation of reserves. Mr. Marshall graduated from the University of Missouri in 1974 with a Bachelor of Science Degree in Geology and from the University of Missouri at Rolla in 1976 with a Master of Science Degree in Geological Engineering. As technical principal, Mr. Marshall meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the DJ Basin. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

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

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

Estimation of Proved Reserves

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2016, 2015 and 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil, natural gas and NGL reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

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

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

Summary of Oil, Natural Gas and NGL Reserves.

The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2016, 2015 and 2014.

	As of December 31,		
	2016	2015	2014
Proved Developed Producing Reserves:			
Oil (MBbls)	13,345	10,769	6,145
Natural gas (MMcf)	93,233	41,773	25,950
NGL (MBbls)	11,453	5,402	3,033
Total (MBoe)(1)	40,337	23,133	13,503
Proved Developed Non-Producing Reserves:			
Oil (MBbls)	3,813	3,480	3,611
Natural gas (MMcf)	14,685	11,238	9,630
NGL (MBbls)	1,901	1,656	1,126
Total (MBoe)(1)	8,162	7,009	6,342
Proved Undeveloped Reserves:			
Oil (MBbls)	73,837	57,252	35,409
Natural gas (MMcf)	399,817	239,572	130,836
NGL (MBbls)	49,094	31,325	15,293
Total (MBoe)(1)	189,567	128,505	72,507
Total Proved Reserves:			
Oil (MBbls)	90,995	71,500	45,165
Natural gas (MMcf)	507,735	292,584	166,416
NGL (MBbls)	62,448	38,383	19,451
Total (MBoe)(1)	238,066	158,647	92,352

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read “Risk Factors” appearing elsewhere in this Annual Report.

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this Annual Report.

Proved Undeveloped Reserves (“PUDs”)

As of December 31, 2016, our proved undeveloped reserves were composed of 73,837 MBbls of oil, 399,817 MMcf of natural gas and 49,094 MBbls of NGL, for a total of 189,567 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during the years ended December 31, 2016, 2015 and 2014, (in MBoe):

Balance, December 31, 2013	—
Purchases of reserves	31,172
Extensions and discoveries	42,780
Revisions of previous estimates	2,433
Transfers to proved developed	(3,878)
Balance, December 31, 2014	72,507
Purchases of reserves	25,476
Extensions and discoveries	37,470
Revisions of previous estimates	275
Transfers to proved developed	(7,223)
Balance, December 31, 2015	128,505
Purchases of reserves	31,081
Extensions and discoveries	50,882
Revisions of previous estimates	(4,978)
Transfers to proved developed	(15,923)
Balance, December 31, 2016	189,567

Extensions and discoveries of 50,882 MBoe, 37,470 MBoe and 42,780 MBoe during the years ended December 31, 2016, 2015 and 2014, respectively, resulted primarily from new proved undeveloped locations added as a result of the drilling and completion of new wells. Downward revisions of previous estimates of 4,978 MBoe during the year ended December 31, 2016, and upward revisions of 275 MBoe and 2,433 MBoe during the years ended December 31, 2015 and 2014, respectively, resulted primarily from the revisions resulting from price changes and revisions resulting from production and performance.

Estimated future development costs relating to the development of PUDs at December 31, 2016 were projected to be approximately $353.9 million in the year ending December 31, 2017, $406.2 million in 2018, $375.3 million in 2019, $266.7 million in 2020 and $159.7 million in 2021. Costs incurred relating to the development of PUDs were $161.4 million, $94.6 million and $35.1 million during the years ended December 31, 2016, 2015 and 2014, respectively. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking. We converted 15,923 MBoe, 7,223 MBoe and 3,878 MBoe to proved developed producing reserves in the years ended December 31, 2016, 2015 and 2014, respectively.

Productive Wells

As of December 31, 2016, we owned an average 73% working interest in 1,014 gross (738 net) productive wells. As of December 31, 2015, we owned an average 64% working interest in 595 gross (384 net) productive wells. As of December 31, 2014, we owned an average 65% working interest in 262 gross (171 net) productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2016 relating to our leasehold acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

The following table sets forth our gross and net acres of developed and undeveloped oil and gas leases as of December 31, 2016:

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage	
Area	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Core DJ Basin	95,300	77,000	52,500	32,400	147,800	109,400
Other Rockies	77,500	38,900	128,500	74,800	206,000	113,700

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

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We intend to extend all of our material leases to the extent possible and expect to incur $36.2 million to extend every material lease that is set to expire in the next three years, without taking into account the drilling of PUDs and holding leases by production and therefore we do not expect a material reduction in our proved undeveloped reserves as a result of lease expirations. The following table sets forth the undeveloped acreage, as of December 31, 2016, that will expire in the years indicated below unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2017		2018		2019		2020+	
Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Core DJ Basin	14,700	9,400	13,400	9,300	10,600	7,100	11,700	5,800
Other Rockies	79,000	42,600	21,200	14,100	18,900	12,200	9,400	5,900

Drilling Results

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

	For the Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells[(2)]:						
Productive[(1)]	72	54.9	79	60.9	50	33.4
Dry	—	—	—	—	—	—
Exploratory Wells[(2)]:						
Productive[(1)]	—	—	4	3.5	—	—
Dry	—	—	—	—	—	—
Total Wells[(2)]:						
Productive[(1)]	72	54.9	83	64.4	50	33.4
Dry	—	—	—	—	—	—

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

As of December 31, 2016, we had 92 gross (86.4 net) wells in process of varying lateral lengths waiting on gas connect or commencement of completion activities.

Operations

General

We operated 96% of our horizontal production for the year ended December 31, 2016. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

During the year ended December 31, 2016, approximately 83% of our production was sold to four customers. However, we do not believe that the loss of a single purchaser, including these four, would materially affect our business because there are numerous other potential purchasers in the area in which we sell our production. For the years ended December 31, 2016, 2015 and 2014 purchases by the following companies exceeded 10% of our total oil and gas revenues.

	For the Year Ended December 31,		
	2016	2015	2014
Customer A	25 %	— %	— %
Customer B	23 %	30 %	— %
Customer C	19 %	17 %	16 %
Customer D	16 %	17 %	8 %
Customer E	1 %	24 %	54 %

Transportation and Gathering

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is collected from the wellhead to our tank batteries and then transported by the purchaser by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point.

We are subject to long-term delivery commitments for the transportation and gathering of our production. Our oil marketer is currently party to a firm transportation agreement that commenced in November 2016 and has a ten-year term with minimum volume commitments of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven, and 58,000 Bbl/d in years eight through ten, and any failure to satisfy the minimum volume commitments is taken into account when calculating the revenue we receive from the oil marketer. We are also subject to two long-term crude oil gathering commitments. The first has a term of five years for 5,000 Bbl/d in year one and 3,800 Bbl/d in years two through five and the second has a term of seven years for 4,000 Bbl/d in years one through three, 2,500 Bbl/d in year four, and 1,500 Bbl/d in years five through seven.

In collaboration with several other producers and DCP Midstream, we have agreed to participate in the expansion of natural gas gathering and processing capacity in the DJ Basin. The plan includes a new 200 MMcf/d processing plant as well as the expansion of a related gathering system, both currently expected to be completed by late 2018, although the start-up date is undetermined at this time. Our share of the commitment will require 51.5 MMcf per day to be delivered after the plant in-service date for a period of 7 years. Our volume shortfall fee would range between $0.95 and $1.50 per Mcf, in the event we do not meet our minimum volume commitment per month. This contractual obligation can be reduced by our proportionate share of the collective volumes delivered to the plant by other producers in the DJ Basin that are in excess of the total commitment. At this time, we are unable to reasonably estimate the amount of potential volume shortfalls due to the volume pooling with other producers in the DJ Basin.

Competition

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

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

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties 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 that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

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

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

Seasonality of Business

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

Oil and Gas Leases

The typical oil and gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties are generally 80%. Our working interest for all producing wells averages approximately 73% and our net revenue interest is approximately 58%.

Regulation of the Oil and Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (the “FERC”) and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

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

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

Regulation Affecting Sales and Transportation of Commodities

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

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

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to ensure terms and conditions of interstate transportation service are not unduly discriminatory or unduly preferential, to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has additional, jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the Energy Policy Act of 2005 ("EPAct 2005"). Under the EPAct 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the NGA to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to $1.0 million/d per violation. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under FERC Order No. 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (“Order No. 704”). Under Order No. 704, any market participant, including a producer that engages in certain wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to the formation of price indices. Not all types of natural gas sales are required to be reported 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 No. 704. Order No. 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and terms and conditions of service on interstate transportation of liquids, including oil and NGL, under the Interstate Commerce Act, as it existed on October 1, 1977 (“ICA”). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that certain interstate liquids pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be “just and reasonable.” Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

The rates charged by many interstate liquids pipelines are currently adjusted pursuant to an annual indexing methodology established and regulated by FERC, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning July 1, 2011, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC’s regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by obtaining market-based rate authority (demonstrating the pipeline lacks market power), establishing rates by settlement with all existing shippers, or through a cost-of-service approach (if the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology). Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

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

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

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

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations in a particular area.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

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

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. In the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes. Moreover, drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any such change could result in an increase in our as well as the oil and natural gas exploration and production industry's costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations where such substances have been taken for treatment 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 activities to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The EPA has issued final rules attempting to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts. Litigation surrounding this rule is on-going. On February 28, 2017, President Trump issued an Executive Order directing the EPA and the U.S. Corps of Engineers to review and, consistent applicable law, initiate rulemaking to rescind or revise the rule. With issuance of the Executive Order, it remains uncertain what actions, if any, the government will take in the pending litigation regarding the final rule and what will be the results of the review by the EPA and the U.S. Corps of Engineers.

The Oil Pollution Act of 1990 ("OPA"), amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Subsurface Injections

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near belowground disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states have imposed more stringent permitting and operating requirements for produced water disposal wells. For example, in Colorado, permit applications are reviewed specifically to evaluate seismic activity. As of 2011, Colorado has required operators to identify potential faults near proposed wells, if earthquakes historically occurred in the area, and to accept maximum injection pressures and volumes based on fracture gradient as conditions to permit approval. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability and results of operation.

Air Emissions

The Clean Air Act (the "CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be charged royalties on natural gas losses or required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from the current standard of 75 parts per billion ("ppb") for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. States are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. Compliance with this or other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Regulation of Greenhouse Gas ("GHG") Emissions

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the CAA that, among other things, establish permitting reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued an Information Collection Request ("ICR") seeking information about methane emissions from facilities and operators in the oil and natural gas industry that could be used to develop Existing Source

Performance Standards, but on March 2, 2017, the EPA announced that it was withdrawing the ICR so that the agency may further assess the need for the information that it was collecting through the request. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from, our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. Finally, it should be noted that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations. 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 natural gas and/or oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies. However, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting; published in June 2016 an effluent limited guideline final rule pursuant to authority under the SWDA prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") published a final rule in March 2015, establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands, but in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government. Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. Moreover, states could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Also, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state more difficult in the future. However, during the November 2016 voting process, one proposed amendment placed on the Colorado state ballot making it relatively more difficult to place an initiative on the state ballot was passed by the voters. As a result, there are more stringent procedures now in place for placing an initiative on a state ballot. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing process and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

In the event that local or state restrictions or prohibitions are adopted in areas where we conduct operations, including the DJ Basin in Colorado, that impose more stringent limitations on the production and development of oil and natural gas, including, among other things, the development of increased setback distances, we and similarly situated oil and natural exploration and production operators in the state may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we and similarly situated operates are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Activities on Federal Lands

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. While we currently have minimal exploration, development and production activities on federal lands, our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

Endangered Species and Migratory Birds Considerations

The federal Endangered Species Act ("ESA"), and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migrating birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of one or more agreements entered into by the U.S. Fish and Wildlife Service, the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

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

Related Permits and Authorizations

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

Related Insurance

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

Employees

As of December 31, 2016, we employed 161 people. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

From time to time we utilize the services of independent contractors to perform various field and other services.

Facilities

Our corporate headquarters is located in Denver, Colorado.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the Securities Exchange Commission (“SEC”) under the Exchange Act. The public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549, on official business days during the hours of 10 a.m. to 3 p.m. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC- 0330. The SEC also maintains an internet website at ww.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

Our common stock is listed and traded on the NASDAQ under the symbol “XOG.” Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the offices of the NASDAQ, at One Liberty Plaza, 165 Broadway, New York, New York 10006.

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

ITEM 1A. RISK FACTORS

RISK FACTORS

There are many factors that may affect our business and results of operations. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business.

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

Oil and natural gas prices are volatile. An extended or further decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, natural gas and NGL are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. For example, during the period from January 1, 2014 to December 31, 2016, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu during the same period. The duration and magnitude of the recent decline in oil prices cannot be predicted. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGL;
- the price and quantity of foreign imports;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls;
- weather conditions;
- technological advances affecting energy consumption;
- the effect of worldwide energy conservation and environmental protection efforts;
- the price and availability of alternative fuels;
- domestic, local and foreign governmental regulation and taxes; and
- shareholder activism and activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas so as to minimize emissions of GHG.

Since November 2014, prices for U.S. oil have weakened in response to continued high levels of production, a buildup in inventories and lower global demand. Prices for oil have showed some recovery beginning in late 2016, but remain significantly below 2014 levels.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGL that we can produce economically and may impact our ability to satisfy our obligations under firm-commitment transportation agreements. We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements may be limited, and we are not under an obligation to hedge a specific portion of our oil or natural gas production.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including 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. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate 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 or ability to finance planned capital expenditures.

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

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

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

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

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

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of oil and natural gas reserves. We expect to fund our 2017 capital expenditures with the proceeds of the IPO, the Private Placement, cash generated by operations, borrowings under our revolving credit facility and possibly through asset sales or additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, 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 from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

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

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- the availability of takeaway capacity;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our revolving credit facility.

If our revenues or the borrowing base under our revolving credit facility decreases 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 and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit 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 would adversely affect our business, financial condition and results of operations.

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

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

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

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

- delays imposed by or resulting from compliance with environmental and other regulatory requirements including limitations on or resulting from wastewater discharge and disposal, subsurface injections, GHG emissions and hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents, such as fires or blowouts;

- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards, tornados and ice storms;
- issues related to compliance with environmental and other governmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGL prices;
- limited availability of financing at acceptable terms;
- title problems or legal disputes regarding leasehold rights; and
- limitations in the market for oil, natural gas and NGL.

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

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

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

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

Our debt arrangements contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make certain acquisitions and investments;
- enter into mergers, consolidations or other transactions resulting in the transfer of all or substantially all of our assets;

- make certain payments, including paying dividends or distributions in respect of our equity;
- hedge future production or interest rates;
- redeem and prepay other debt;
- holding cash balances in excess of certain thresholds while carrying a balance of our revolving credit facility;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

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

Our revolving credit facility limits the amount we can borrow up to the lower of our aggregate lender commitments and a borrowing base amount, which the lenders, in their sole discretion, will determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties securing our loan. The lenders will be able to unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders does not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. As of December 31, 2016, our borrowing base was $475.0 million.

A breach of any covenant in our revolving credit facility will result in a default under the revolving credit facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and 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. In addition, our obligations under our revolving credit facility are secured by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets.

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 our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our Senior Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or decline, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our revolving credit facility and the indenture governing our 2021 Notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

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

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGL, we enter into commodity derivative contracts for a significant portion of our production, primarily consisting of swaps, put options and call options. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Sources of Our Revenues." Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

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

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

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

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

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

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

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

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

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2016 were calculated under SEC rules using the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months of $42.75/Bbl for oil and $2.49/MMBtu for natural gas, which for certain periods of 2016 were substantially above the available spot oil and natural gas prices. Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits.

There is a limited amount of production data from horizontal wells completed in the DJ Basin. As a result, reserve estimates associated with horizontal wells in this area are subject to greater uncertainty than estimates associated with reserves attributable to vertical wells in the same area.

Reserve engineers rely in part on the production history of nearby wells in establishing reserve estimates for a particular well or field. Horizontal drilling in the DJ Basin is a relatively recent development, whereas vertical drilling has been utilized by producers in this area for over 50 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small compared to that of production data from vertical wells. Until a greater number of horizontal wells have been completed in the DJ Basin, and a longer production history from these wells has been established, there may be a greater variance in our proved reserves on a year-over-year basis due to the transition from vertical to horizontal reserves in both the proved developed and proved undeveloped categories. We cannot assure you that any such variance would not be material and any such variance could have a material and adverse impact on our cash flows and results of operations. If our horizontal wells do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

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

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. As of December 31, 2016, we have drilled 352 gross one-mile equivalent horizontal wells and have completed 274 gross one-mile equivalent horizontal wells, and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. In addition, our horizontal drilling activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Approximately 48% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2016, approximately 48% of our net leasehold acreage was undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Substantially all of our producing properties are located in the DJ Basin of Colorado, making us vulnerable to risks associated with operating in one major geographic area. Specifically, as the DJ Basin is an area of high industry activity, we may be unable to hire, train or retain qualified personnel needed to manage and operate our assets.

Substantially all of our producing properties are geographically concentrated in the DJ Basin of Colorado, an area in which industry activity has increased rapidly. At December 31, 2016, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGL.

Specifically, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years and may increase substantially in the future. Moreover, our competitors, including those operating in multiple basins, may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could have a negative effect on production volumes or significantly increase costs, which could have a material adverse effect on our results of operations, liquidity and financial condition.

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

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

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

The marketing of oil and natural gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities are unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. For example, recent increases in activity in the DJ Basin have contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Capacity constraints typically reduce the productivity of some of our older vertical wells and may on occasion limit incremental production from some of our newer horizontal wells. This constrains our production and reduces our revenue from the affected wells. Capacity constraints affecting natural gas production also impact the associated NGL. We are also dependent on the availability and capacity of oil purchasers for our production. Increases in the amount of oil that we transport out of the DJ Basin for sale would result in an increase in our transportation costs and would reduce the price we receive for the affected production.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the DJ Basin, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

While we have undertaken initiatives to expand our access to midstream and operational infrastructure, these initiatives may be delayed or unsuccessful. As a result, our business, financial condition and results of operations could be adversely affected.

We are required to pay fees to our service providers based on minimum volumes under a long-term contract regardless of actual volume throughput.

We may enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments. Our oil marketer is currently party to a firm transportation agreement that commenced in November 2016 and has a ten-year term, which obligates them to meet delivery commitments of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven, and 58,000 Bbl/d in years eight through ten and any failure to satisfy the minimum volume commitments is taken into account when calculating the revenue we receive from the oil marketer. We are also subject to two long-term crude oil gathering commitments. The first has a term of five years for 5,000 Bbl/d in year one and 3,800 Bbl/d in years two through five and the second has a term of seven years for 4,000 Bbl/d in years one through three, 2,500 Bbl/d in year four, and 1,500 Bbl/d in years five through seven. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation and processing capacity. As of December 31, 2016, the aggregate amount of estimated payments over the ten-year term of these agreements was $951.2 million. If we have insufficient production to meet the minimum volumes under this agreement or any other firm commitment agreement we may enter into, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results or operations.

The prices we receive for our production may be affected by local and regional factors.

The prices we receive for our production will be determined to a significant extent by factors affecting the local and regional supply of and demand for oil and natural gas, including the adequacy of the pipeline and processing infrastructure in the region to process, and transport, our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and natural gas production and the actual price we receive for our production, which may be lower than index prices. If the price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

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

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

Changes in the legal and regulatory environment governing the oil and natural gas industry, particularly changes in the current Colorado forced pooling system, could have a material adverse effect on our business.

Our business is subject to various forms of government regulation, including laws and regulations concerning the location, spacing and permitting of the oil and natural gas wells we drill, among other matters. In particular, our business utilizes a methodology available in Colorado known as “forced pooling,” which refers to the ability of a holder of an oil and natural gas interest in a particular prospective drilling spacing unit to apply to the Colorado Oil & Gas Conservation Commission for an order forcing all other holders of oil and natural gas interests in such area into a common pool for purposes of developing that drilling spacing unit. This methodology is especially important for our operations in the Greeley area, where there are many interest holders. Changes in the legal and regulatory environment governing our industry, particularly any changes to Colorado forced pooling procedures that make forced pooling more difficult to accomplish, could result in increased compliance costs and adversely affect our business, financial condition and results of operations.

SEC rules could limit our ability to book additional PUDs in the future.

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

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

At December 31, 2016, approximately 80% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 189,567 MBoe of estimated proved undeveloped reserves will require an estimated $1.6 billion of development capital over the next five years.

Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast, as well as access to liquidity sources, such as the capital markets, our revolving credit facility and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of the applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will 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 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 such as lease expirations, changes in drilling plans and adverse drilling results, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings. If market or other economic conditions deteriorate or if oil, natural gas and NGL prices continue to decline, we may incur impairment charges in 2017 or later periods, which may have a material adverse effect on our results of operations.

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

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

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

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

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

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

The inability of one or more of our purchasers to meet their obligations may adversely affect our financial results.

We have exposure to credit risk through receivables from purchasers of our oil, natural gas and NGL production. Four, four and three purchasers accounted for more than 10% of our revenues in the years ended December 31, 2016, 2015, and 2014 respectively. This concentration of purchasers may impact our overall credit risk in that these entities may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. The inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition and results of operations.

A substantial portion of our reserves is located in urban areas, which could increase our costs of development and delay production.

A substantial portion of our reserves are located in urban portions of the DJ Basin, which could disproportionately expose us to operational and regulatory risk in that area. Much of our operations are within the city limits of various municipalities in northeastern Colorado. In such urban and other populated areas, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our production to market in such areas may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

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

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

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases.

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. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of insurance proceeds for covered events 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, natural gas or NGL in commercially viable quantities.

Properties that we decide to drill that do not yield oil, natural gas or NGL 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 cancelled as a result of numerous factors, including:

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

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

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

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

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

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

In addition, our debt arrangements will impose certain limitations on our ability to enter into mergers or combination transactions. Our debt arrangements will also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

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

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or land men who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We are subject to stringent environmental and occupational health and safety laws and regulations that could expose us to significant costs and liabilities.

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may 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, often requiring costly actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays in permitting or development of projects and the issuance of orders limiting or prohibiting some or all of our operations in a particular area.

The performance of our operations may result in significant environmental costs and liabilities due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances could expose us to material losses, expenditures and liabilities under environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground-level ozone from the current standard of 75 ppb for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. States are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. In a second example, in response to recent seismic events near belowground disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states, including Colorado, have imposed more stringent permitting and operating requirements pursuant to SDWA's UIC program for produced water disposal wells. In Colorado, permit applications are reviewed specifically to evaluate seismic activity and, as of 2011, Colorado has required operators to identify potential faults near proposed wells, if earthquakes historically occurred in the area, and to accept maximum injection pressures and volumes based on fracture gradient as conditions to permit approval. We may not be able to recover some or any of our costs with respect to such developments from insurance. See "Business—Regulation of Environmental and Occupational Safety and Health Matters" for a further description of the laws and regulations that affect us.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, natural gas and NGL prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

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

We may be involved in legal proceedings that could result in substantial liabilities.

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.

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and reduced demand for the oil, natural gas and NGL that we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date.

The EPA has, however, adopted rules under authority of the CAA that, among other things, establish permitting reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published the NSPS Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS Subpart OOOO standards published by the EPA in 2012, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued an ICR seeking information about methane emissions from facilities and operators in the oil and natural gas industry that could be used to develop Existing Source Performance Standards, but on March 2, 2017, the EPA announced that it was withdrawing the ICR so that the agency may further assess the need for the information that it was collecting through the request. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from, our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. Finally, it should be noted that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations. 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.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies but several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting; published in June 2016 an effluent limited guideline final rule pursuant to authority under the SDWA prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal BLM published a final rule in March 2015, establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands, including well casing and wastewater storage requirements and an obligation for exploration and production operators to disclose what chemicals they are using in fracturing activities; however, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

The U.S. Congress has, from time to time considered, but not adopted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process.

At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States may elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Also, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state more difficult in the future. However, during the November 2016 voting process, one proposed amendment placed on the Colorado state ballot making it relatively more difficult to place an initiative on the state ballot was passed by the voters. As a result, there are more stringent procedures now in place for placing an initiative on a state ballot. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Please read “Business—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of the laws and regulations that affect us.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, and raising additional capital, which could have a material adverse effect on our business.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business. These risks are greater at times and in areas where the pace of our exploration and development activity slows.

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

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

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

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

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

We have grown rapidly since we began operations in late 2012. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

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

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

Increases in interest rates could adversely affect our business.

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

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

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

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

Adverse weather conditions 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 NGL. 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.

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

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

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

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

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

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of 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 and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil, natural gas and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and NGL. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation including changes to cost recovery rules and to the deductibility of interest expense may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

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

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

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

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets 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 financial assets, 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.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Related to our Common Stock

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

We completed our IPO in October 2016. As a public company, we must comply with various laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NASDAQ, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are now required to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NASDAQ;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act for our fiscal year ending December 31, 2017, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2022. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed.

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. Moreover, if we are not able to comply with the requirements of Section 404 in a timely manner, or if in the future we or our independent registered public accounting firm identifies deficiencies in our internal controls over financial reporting that are deemed to be material weaknesses, the market price of our stock could decline, and we could be subject to sanctions or investigations by the SEC or other regulatory authorities, which would require additional financial and management resources.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

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. If one or more material weaknesses emerge related to financial reporting, or if we otherwise fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected. 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.

Yorktown's funds collectively hold a substantial portion of the voting power of our common stock.

After accounting for the Private Placement, Yorktown's funds currently collectively hold approximately 29% of our common stock. See "Security Ownership of Certain Beneficial Owners and Management" for more information regarding ownership of our common stock by the Yorktown funds. The existence of affiliated stockholders with significant aggregate holdings that may act as a group may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with affiliated stockholders with significant aggregate holdings that may act as a group.

Conflicts of interest could arise in the future between us, on the one hand, and Yorktown and its affiliates, including its funds and their respective portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities.

Yorktown's funds are in the business of making investments in entities in the U.S. energy industry. As a result, Yorktown's funds may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. Yorktown's funds and their respective portfolio companies may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Under our certificate of incorporation, Yorktown's funds and/or one or more of their respective affiliates are permitted to engage in business activities or invest in or acquire businesses which may compete with our business or do business with any client of ours. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

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

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

We do not intend to pay dividends on our common stock, and our debt arrangements and the Series A Preferred Stock place certain restrictions on our ability to do so. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our debt arrangements and the Series A Preferred Stock restrict our ability to pay cash dividends. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if shareholders sell their common stock at a price greater than they paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price that such investors paid for our common stock.

Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute the ownership in us by current shareholders.

We may sell additional shares of common stock in public or private offerings. We may also issue additional shares of common stock or convertible securities. After the Private Placement, and excluding any shares of common stock issued upon the conversion of our Series A Preferred Stock including any shares of Series A Preferred Stock that may be issued pursuant to our option to pay dividends on the Series A Preferred Stock in kind pursuant to the terms of the Certificate of Designations setting forth the terms of the Series A Preferred Stock, we have 171,834,605 outstanding shares of common stock. In connection with the IPO, we filed a registration statement with the SEC on Form S-8 providing for the registration of 23,000,000 shares of our common stock issued or reserved for issuance under our equity incentive plan. Subject to the satisfaction of vesting conditions, the expiration of lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction. Additionally, the Series A Preferred Stock are convertible into shares of our common stock pursuant to their terms.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

The underwriters of the IPO may waive or release parties to the lock-up agreements entered into in connection with the IPO, which could adversely affect the price of our common stock.

In connection with the IPO, we and all of our directors and executive officers and certain of our stockholders have entered into lock-up agreements with respect to their common stock, pursuant to which we and they are subject to certain resale restrictions for a period of 180 days following the effectiveness date of the registration statement filed in connection with the IPO. Credit Suisse Securities (USA) LLC, Barclays Capital Inc. and Goldman, Sachs & Co., at any time and without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

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, (1) 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, (2) 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, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) 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 in a fiscal year, have more than $700 million in market value of our common stock held by non-affiliates, 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, you 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.

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

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

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.

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

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim for a breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 3. LEGAL PROCEEDINGS

We are currently in discussions with the Colorado Department of Public Health and Environment ("CDPHE") regarding its July 2015 Compliance Advisory issued to the Company, which alleged air quality violations at three of our facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. The CDPHE subsequently expanded its investigation to several additional facilities of ours and, more recently, has indicated to us that it is further expanding its investigation to our other facilities in Colorado and intends to seek a field-wide administrative settlement of these issues. We cannot predict the outcome of this matter at this time.

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information.

Our common stock is currently traded on the NASDAQ under the ticker symbol "XOG." The following table presents the range of high and low intraday sales prices per share for the indicated period in 2016, as reported by NASDAQ:

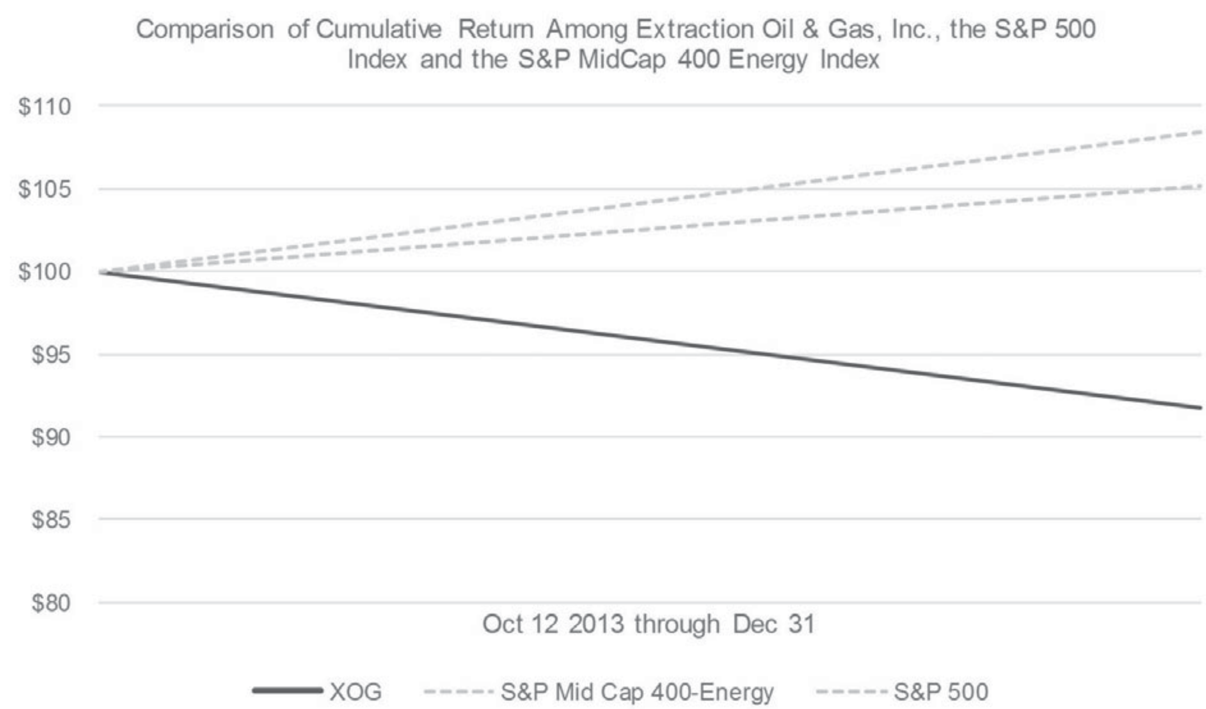
Period	High	Low
From October 12, 2016 to December 31, 2016	$ 25.08	$ 19.10

Dividend Policy

We have not historically paid, and do not anticipate paying any cash dividends in the future, to common stockholders of our common stock. In addition, our revolving credit facility, our Senior Notes (collectively, our "debt arrangements") and the Series A Preferred Stock place certain restrictions on our ability to pay cash dividends. Please see *Note 5 — Long Term Debt* included in the notes to the consolidated financial statements included elsewhere in this Annual Report for more information regarding the restrictions placed on our ability to pay cash dividends.

Comparison of Cumulative Return

The following graph compares the cumulative total shareholder return on a $100 investment in our common stock on October 12, 2016 through December 31, 2016, to that of the cumulative return on a $100 investment in the S&P 500 Composite for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.



Holders

Pursuant to the records of the transfer agent, as of March 10, 2017, the number of holders of record of our common stock was 224.

Sales of Unregistered Securities

We did not have any sales of unregistered securities during the fiscal year ended December 31, 2016, except as set forth in our Current Reports on Form 8-k filed during such fiscal year.

Issuer Purchases of Equity Securities

We did not purchase any shares of our common stock during the period of October 12, 2016 through December 31, 2016.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data as of and for the years ended December 31, 2014 through December 31, 2016. The data as of and for the fiscal years ended December 31 for each respective year was derived from our historical consolidated financial statements and the accompanying notes included elsewhere in this Annual Report.

The following selected consolidated financial information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations" and the consolidated financial statements and the notes thereto included in "Item 8. Financial Statements and Supplementary Data" presented elsewhere in this Annual Report for further discussion of the factors affecting the comparability of the Company's financial data. Also see "Recent Accounting Pronouncements" included in the notes to the consolidated financial statements included elsewhere in this Annual Report.

	For the Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil sales	$ 194,059	$ 157,024	$ 75,460
Natural gas sales	48,652	26,019	9,247
NGL sales	35,378	14,707	8,133
Total Revenues	278,089	197,750	92,840
Operating Expenses:			
Lease operating expenses	62,043	30,628	5,067
Production taxes	20,730	17,035	9,743
Exploration expenses	36,422	18,636	126
Depletion, depreciation, amortization and accretion	205,348	146,547	34,042
Impairment of long lived assets	23,425	15,778	—
Other operating expenses	10,891	2,353	—
Acquisition transaction expenses	2,719	6,000	—
General and administrative expenses	232,388	37,149	19,598
Total Operating Expenses	593,966	274,126	68,576
Operating Income (Loss)	(315,877)	(76,376)	24,264
Other Income (Expense):			
Commodity derivatives gain (loss)	(100,947)	79,932	48,008
Interest expense	(68,843)	(51,030)	(22,454)
Other income	386	210	24
Total Other Income (Expense)	(169,404)	29,112	25,578
Net Income (Loss) Before Income Taxes	(485,281)	(47,264)	49,842
Income Tax Benefit: (2)	29,280	—	—
Net Income (Loss)	$ (456,001)	$ (47,264)	$ 49,842
Loss Per Common Share (1)			
Basic and diluted	$ (1.54)		
Total Production Volumes:			
Oil (MBbls)	5,287	3,946	1,022
Natural Gas (MMcf)	20,212	10,823	2,664
NGLs (MBbls)	2,284	1,335	325
Total (MBOE)	10,940	7,084	1,792
Average net sales (BOE/d)	29,891	19,408	4,908
Proved Reserves:			
Oil (MBbls)	90,995	71,500	45,165
Natural Gas (MMcf)	507,735	292,584	166,416
NGLs (MBbls)	62,448	38,383	19,451
Total (MBOE)	238,066	158,647	92,352

Selected consolidated financial information continued:

	For the Year Ended December 31,		
	2016	2015	2014
Consolidated Cash Flow Information:			
Net cash provided by operating activities	$ 116,388	$ 166,683	$ 77,390
Net cash used in investing activities	$ (915,808)	$ (520,006)	$ (970,640)
Net cash provided by financing activities	$ 1,291,050	$ 371,404	$ 972,090
Consolidated Balance Sheet Information:			
Total Assets	$ 2,784,776	$ 1,634,140	$ 1,201,069
Long-term Debt	$ 538,141	$ 637,790	$ 508,903
Series A Preferred Stock	$ 153,139	$ —	$ —
Total Equity	$ 1,616,073	$ 754,232	$ 545,188
Other Financial Data (3):			
Adjusted EBITDAX	$ 192,265	$ 176,120	$ 66,892

(1) See *Note 9 — Members' and Shareholders' Equity* and *Note 12 — Earnings (Loss) Per Share* in our consolidated financial statements, included herein, for additional discussion regarding the calculation of loss per share for 2016.

(2) Extraction Oil & Gas, Inc. is a subchapter C corporation ("C-Corp") under the Internal Revenue Code of 1986, as amended, and is subject to federal and State of Colorado income taxes. Our predecessor, Extraction Oil & Gas Holdings, LLC was not subject to U.S. federal income taxes. As a result, the consolidated net income (loss) in our historical financial statements for periods prior to our October 12, 2016 corporate reorganization to a C-Corp does not reflect the tax expense we would have incurred as a C-Corp during such periods.

(3) Adjusted EBITDAX is a non-GAAP financial measure. Management defines Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depreciation, depletion, amortization and accretion ("DD&A"), impairment of long lived assets, exploration expenses, rig termination fees, acquisition transaction expenses, commodity derivative (gain) loss, settlements on commodity derivatives, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, interest expense, income taxes and non-recurring charges. See Part II, Item & - Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report for additional disclosures related to Adjusted EBITDAX.

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

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

OVERVIEW

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin. We are focused on growing our proved reserves and production primarily through the development of our large inventory of identified liquids-rich horizontal drilling locations.

Our Properties

We have assembled, as of December 31, 2016, approximately 109,400 net acres of large, contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin as indicated by the results of our horizontal drilling program and the results of offset operators. Additionally, we hold approximately 113,700 net acres outside of what we consider our Core DJ Basin, which we refer to as our "Other Rockies Area," that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. We operated 96% of our horizontal production for the year ended December 31, 2016, our total estimated proved reserves were approximately 238.1 MMBoe, of which approximately 20% were classified as proved developed reserves. For more information about our properties, please read "Business—Our Properties."

Financial Overview

For the year ended December 31, 2016, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $306.7 million as compared to $255.4 million in the same prior year period due to an increase in sales volumes of 3,856.0 MBoe, offset primarily by a decline of $8.02 in realized price per BOE, including settled derivatives.

For the year ended December 31, 2016, we had a net loss of $456.0 million as compared to net loss of $47.3 million for the year ended December 31, 2015. The increase in net loss was driven by non-cash compensation expense of $200.3 million primarily related to the IPO and a net loss on commodity derivatives of $100.9 million, primarily due to the increase in NYMEX crude oil futures prices as December 31, 2016 compared to December 31, 2015 and change in fair value from the execution of new positions.

Adjusted EBITDAX was $192.3 million for the year ended December 31, 2016, as compared to $176.1 million in the same period in 2015, reflecting a 9% increase. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Overview

During the year ended December 31, 2016, we continued to focus on growing production while at the same time implementing operational efficiencies to reduce drilling and completion costs. We drilled 103 gross (89.8 net) horizontal wells and completed 72 gross (54.9 net) horizontal wells in the DJ Basin. As of January 2017, we are currently running a full time three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program.

Recent Developments

Recent Acquisitions

November 2016 Acquisition

On November 22, 2016, we acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the Core DJ Basin for approximately $120.0 million, including customary closing adjustments. We also made an additional $41.1 million deposit in November 2016 in conjunction with November 2016 Acquisition, which has been reflected in the December 31, 2016 consolidated balance sheet within the cash held in escrow line item. The deposit was made for two additional closings of leaseholds located in the Core DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres. The second closing is expected to occur in the first half of 2017 and will add approximately 800 net acres.

October 2016 Acquisition

On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field for total consideration of $405.3 million in cash, subject to customary purchase price adjustments (the "Bayswater Acquisition" or "October 2016 Acquisition"). Upon completion of the Bayswater Acquisition, we acquired producing and non-producing assets primarily located in the central and northwest portions of the Wattenberg Field from an existing working interest partner, primarily around our existing Greeley and Windsor areas. The Bayswater Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The Bayswater acquisition provided net daily production of approximately 6,900 BOE/d during the fourth quarter of 2016. We funded the purchase price through the issuance of $260.3 million in convertible preferred securities and borrowings under our revolving credit facility.

Option to Acquire Additional Assets from October 2016 Acquisition

In connection with the consummation of the Bayswater Acquisition, we paid $10.0 million for an option to purchase additional assets from Bayswater for an additional $190.0 million, for a total purchase price of $200.0 million (the "Additional Bayswater Assets"). The option allowed us to exercise at any time until March 31, 2017. If we were to not exercise our option to acquire the Additional Bayswater Assets, Bayswater would have the right until April 30, 2017 to elect to sell those assets to us for an additional $120.0 million, for a total purchase price for the Additional Bayswater Assets of $130.0 million. In March 2017, we entered into an amendment to this agreement with Bayswater to terminate both our and Bayswater's options for no further consideration. The $10.0 million was expensed in the fourth quarter of 2016 to other operating expenses within our consolidated statements of operations.

August 2016 Acquisition

On August 23, 2016, we acquired an unaffiliated oil and gas company's interests in approximately 1,100 net acres of leasehold located the Core DJ Basin for approximately $13.7 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date on August 23, 2016. We expect to close on approximately 300 additional net acres related to this acquisition in the first half of 2017 for an additional $3.4 million.

Capital Raises and Corporate Reorganization

Private Placement of Common Stock

On December 15, 2016, we issued approximately 25.0 million shares of common stock, at a price of $18.25 per share, in a private placement of our common stock (the “Private Placement”). The Private Placement resulted in approximately $457.0 million of gross proceeds and approximately $441.9 million of net proceeds (after deducting placement agent commission and offering expenses). The offering of the common stock issued in connection with the Private Placement was registered in a Form S-1, filed on January 9, 2017. Proceeds from the Private Placement are going to be used for general corporate purposes, including to fund the Company’s 2017 capital expenditures.

Initial Public Offering

On October 17, 2016, we completed an initial public offering (“IPO”) of approximately 33.3 million shares of our common stock at a price to the public of $19.00 per share and we became a publicly traded company listed on the NASDAQ Global Select Market (“NASDAQ”) under the ticker symbol “XOG”. After deducting underwriting discounts and commissions and estimated offering expenses payable by us, we received approximately $681.0 million of aggregate net proceeds from our IPO after the underwriters exercised their option on October 24, 2016 to purchase 5.0 million additional shares in full. We used (i) $90.0 million of the net proceeds from the Offering to redeem in full the Series A Preferred Units (as defined below) and (ii) $291.6 million to repay borrowings under our revolving credit facility. We intend to use the remaining net proceeds for general corporate purposes, including to fund our 2017 capital expenditures.

Corporate Reorganization

Extraction Oil & Gas, Inc., formerly known as Extraction Oil & Gas, LLC, was converted from a Delaware limited liability company to a Delaware corporation, on October 12, 2016. In connection with the IPO on October 17, 2016, Extraction Oil & Gas Holdings, LLC (“Holdings”) was merged with and into Extraction, and Extraction was the surviving entity to the merger (the “Corporate Reorganization”). All equity holders in Holdings, other than the holders of the Series B Preferred Units (which were converted in connection with the closing of the IPO into shares of Series A Preferred Stock), but including the holders of restricted units and incentive units, received approximately 108.5 million shares of our common stock, with the allocation of such shares among our existing equity holders determined, pursuant to the terms of the limited liability company agreement of Holdings, by reference to an implied valuation based on the 10-day volume weighted average price of Extraction’s common stock following the closing of the IPO. The merger was treated as a reorganization of entities under common control. As part of Holdings' merger with and into Extraction, all of Holdings' other subsidiaries became direct or indirect subsidiaries of Extraction.

Convertible Preferred Securities

We previously issued to affiliates of Apollo Capital Management (“Apollo”) $75.0 million in Series A Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. In connection with the consummation of the IPO, we used $90.0 million of the net proceeds to redeem the Series A Preferred Units in full, which included a premium of $15.0 million.

In addition, we have issued to, among others, investment funds affiliated with OZ Management LP and Yorktown Partners LLC (“Yorktown”) $185.3 million in Series B Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and we had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units were converted in connection with the closing of the IPO into shares of our Series A Preferred Stock that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). Beginning on or after the later of (a) 90 days after the closing of the IPO and (b) the earlier of 120 days after the closing of the IPO and the expiration of the lock-up period contained in the underwriting agreement entered into in connection with the IPO (the "Lock-Up Period End Date"), the Series A Preferred Stock will be convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the IPO, we may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference.

Amendment to Revolving Credit Facility

On December 7, 2016, the borrowing base of our revolving credit facility was increased from $450.0 million to $475.0 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Revolving Credit Facility."

Income Taxes

In connection with the IPO, Holdings was merged into the Company. Prior to this corporate reorganization, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings' taxable income was passed through to our members. Beginning October 12, 2016, we began to be taxed as a C corporation under the Internal Revenue Code and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings.

How We Evaluate Our Operations

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

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses ("LOE");
- Capital expenditures; and
- Adjusted EBITDAX (a Non-GAAP measure).

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the year ended December 31, 2014, our revenues were derived 81% from oil sales, 10% from natural gas sales and 9% from NGL sales. For the year ended December 31, 2015, our revenues were derived 79% from oil sales, 13% from natural gas sales and 8% from NGL sales. For the year ended December 31, 2016, our revenues were derived 70% from oil sales, 17% from natural gas sales and 13% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

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

	For the Year Ended December 31,		
	2016	2015	2014
Oil (MBbl)	5,287	3,946	1,022
Natural gas (MMcf)	20,212	10,823	2,664
NGL (MBbl)	2,284	1,335	325
Total (MBoe)	10,940	7,084	1,792
Average net sales (BOE/d)	29,891	19,408	4,908

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read “Risks Related to the Oil, Natural Gas and NGL Industry and Our Business” in Item 1A. of this Annual Report for a further description of the risks that affect us.

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

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2014 to December 31, 2016, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015 and continuing during 2016 are due to a combination of factors including increased U.S. supply, global economic concerns and geopolitical risks. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas’ proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. In the table below, the NYMEX averages and our average realized prices, with and without derivative settlements, are calculated based on the average of each month's prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Year Ended December 31,		
	2016	2015	2014
Oil			
NYMEX WTI High ($/Bbl)	$ 54.06	$ 61.43	$ 107.26
NYMEX WTI Low ($/Bbl)	$ 26.21	$ 34.73	$ 53.27
NYMEX WTI Average ($/Bbl)	$ 43.32	$ 48.80	$ 93.00
Average Realized Price ($/Bbl)	$ 36.64	$ 39.85	$ 81.48
Average Realized Price, with derivative settlements ($/Bbl)	$ 40.62	$ 53.97	$ 83.59
Average Realized Price as a % of Average NYMEX WTI	84.6 %	81.7 %	87.6 %
Differential ($/Bbl) to Average NYMEX WTI	$ (6.68)	$ (8.94)	$ (11.52)
Natural Gas			
NYMEX Henry Hub High ($/MMBtu)	$ 3.93	$ 3.23	$ 6.15
NYMEX Henry Hub Low ($/MMBtu)	$ 1.64	$ 1.76	$ 2.89
NYMEX Henry Hub Average ($/MMBtu)	$ 2.55	$ 2.63	$ 4.28
Average Realized Price ($/Mcf)	$ 2.32	$ 2.43	$ 4.11
Average Realized Price, with derivative settlements ($/Mcf)	$ 2.82	$ 2.82	$ 4.11
Average Realized Price as a % of Average NYMEX Henry Hub(1)	82.7 %	84.0 %	87.3 %
Differential ($/Mcf) to Average NYMEX Henry Hub(1)	$ (0.49)	$ (0.46)	$ (0.60)
NGL			
Average Realized Price ($/Bbl)	$ 14.74	$ 11.02	$ 27.20
Averaged Realized Price as a % of Average NYMEX WTI	33.6 %	22.6 %	29.2 %

(1) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—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 will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options, and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agreed to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and, we are not obligated to hedge a specific portion of our oil or natural gas production. The following summarizes our derivative positions related to crude oil and natural gas sales in effect as of December 31, 2016:

	2017	2018
NYMEX WTI(1) Crude Swaps:		
Notional volume (Bbl)	1,500,000	900,000
Weighted average fixed price ($/Bbl)	$ 43.84	$ 55.94
NYMEX WTI(1) Crude Sold Calls:		
Notional volume (Bbl)	6,000,000	3,400,000
Weighted average sold call price ($/Bbl)	$ 55.91	$ 62.26
NYMEX WTI(1) Crude Sold Puts:		
Notional volume (Bbl)	6,100,000	3,000,000
Weighted average sold put price ($/Bbl)	$ 37.74	40.00
NYMEX WTI(1) Crude Purchased Puts:		
Notional volume (Bbl)	6,000,000	3,300,000
Weighted average purchased put price ($/Bbl)	$ 47.64	$ 50.00
NYMEX HH(2) Natural Gas Swaps:		
Notional volume (MMBtu)	25,420,000	12,000,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH(2) Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH(2) Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG(3) Basis Gas Swaps:		
Notional volume (MMBtu)	990,000	—
Weighted average fixed basis price ($/MMBtu)	$ (0.19)	

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Year Ended December 31, 2016	2015	2014
NYMEX HH(1) Natural Gas Swaps:			
Notional volume (MMBtu)	13,194,600	6,444,552	761,766
Weighted average fixed price ($/MMBtu)	$ 3.13	$ 3.27	$ 3.92
CIG(3) Basis Gas Swaps:			
Notional volume (MMBtu)	2,970,000	—	—
Weighted average fixed price ($/MMBtu)	$ (0.19)	$	$
NYMEX WTI(2) Crude Swaps:			
Notional volume (Bbl)	1,989,060	1,293,769	262,993
Weighted average fixed price ($/Bbl)	$ 41.87	$ 76.24	$ 94.65
NYMEX WTI(2) Crude Sold Puts:			
Notional volume (Bbl)	2,100,000	—	—
Weighted average fixed price ($/Bbl)	$ 44.93	$	$
NYMEX WTI(2) Crude Purchased Puts:			
Notional volume (Bbl)	4,724,150	1,943,588	—
Weighted average purchased put price ($/Bbl)	$ 51.82	$ 57.67	$
NYMEX WTI(2) Crude Sold Calls:			
Notional volume (Bbl)	2,786,090	1,943,588	—
Weighted average fixed price ($/Bbl)	$ 59.44	$ 67.21	$
NYMEX WTI(2) Crude Purchased Calls:			
Notional volume (Bbl)	216,000	—	—
Weighted average fixed price ($/Bbl)	$ 69.58	$	$
Total Amounts Received/(Paid) from Settlement (in thousands)	**$ 34,196**	**$ 59,785**	**$ 3,974**
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ 8,631	$ (4,015)	$ (2,250)
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	**$ 42,827**	**$ 55,770**	**$ 1,724**

(1) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(2) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses. LOEs also include expenses incurred to gather and deliver natural gas to the processing plant and/or selling point.

Capital Expenditures

For the year ended December 31, 2016, we incurred approximately $317.5 million in drilling 103 gross (90 net) wells with an average lateral length of 1.5 miles and completing 72 gross (55 net) wells with an average lateral length of 1.3 miles. In addition, we incurred approximately $32.1 million of leaseholds and surface acreage additions and approximately $5.1 million of midstream, excluding amounts that were paid for acquisitions. Our 2016 budget allocated approximately $335.0 million to the drilling of 100 gross (90 net) wells with an average lateral length of 1.5 miles and the completion of 92 gross (82 net) wells with an average lateral length of 1.3 miles, approximately $5.0 million to midstream, and approximately $25.0 million to leaseholds, excluding amounts that were paid for acquisitions. We transitioned to enhanced completions during the fourth quarter of 2016. These enhanced completions are included in our 2017 budget and guidance, however, they were not included in our 2016 budget, which resulted in fewer wells completed than budgeted during 2016.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program. Our capital budget excludes any amounts that were or may be paid for potential acquisitions.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("GAAP"). Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depreciation, depletion, amortization and accretion ("DD&A"), impairment of long lived assets, exploration expenses, rig termination fees, acquisition transaction expenses, commodity derivative (gain) loss, settlements on commodity derivatives, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, interest expense, income taxes, and non-recurring charges.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) 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 (loss) 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, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our Board of Directors as a performance measure in determining executive compensation.

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

	For the Year Ended December 31,		
	2016	2015	2014
Reconciliation of Adjusted EBITDAX:			
Net income (loss)	$ (456,001)	$ (47,264)	$ 49,842
Add back:			
Depreciation, depletion, amortization, and accretion	205,348	146,547	34,042
Impairment of long lived assets	23,425	15,778	—
Exploration expenses	36,422	18,636	126
Rig termination fee	891	1,657	—
Write-off of deposit on acquisition	10,000	—	—
Acquisition transaction expenses	2,719	6,000	—
(Gain) loss on commodity derivatives	100,947	(79,932)	(48,008)
Settlements on commodity derivative instruments	34,196	59,785	3,974
Premiums paid for derivatives that settled during the period	(5,553)	(2,087)	—
Unit and stock-based compensation expense	200,308	5,970	4,462
Amortization of debt discount and debt issuance costs	19,256	5,604	1,985
Interest expense	49,587	45,426	20,469
Income tax benefit	(29,280)	—	—
Adjusted EBITDAX	$ 192,265	$ 176,120	$ 66,892

Items Affecting the Comparability of Our Financial Results

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

- On May 29, 2014, we acquired interests in approximately 6,200 net acres of leaseholds and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "May 2014 Acquisition"). The May 2014 Acquisition included 22 producing wells and, at the time of acquisition, had net daily production of approximately 3,000 BOE/d.
- On July 28, 2014, we acquired interests in approximately 9,000 net acres of leaseholds and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "July 2014 Acquisition"). The July 2014 Acquisition included 126 producing wells and, at the time of acquisition, had net daily production of 900 BOE/d.
- On August 21, 2014, we acquired interests in approximately 6,400 net acres of leaseholds and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "August 2014 Acquisition"). The August 2014 Acquisition included 94 producing wells and, at the time of acquisition, had net daily production of 2,600 BOE/d.
- On October 15, 2014, we acquired interests in approximately 9,200 net acres of leaseholds and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "October 2014 Acquisition"). The October 2014 Acquisition included 29 producing wells and, at the time of acquisition, had net daily production of 232 BOE/d.
- On March 10, 2015, we acquired interests in approximately 39,000 net acres of leaseholds and related producing properties located primarily in Adams, Broomfield, Boulder and Weld Counties, Colorado, along with various related rights, permits, contracts, equipment and other assets (the "March 2015 Acquisition"). The March 2015 Acquisition included 444 producing wells and, at the time of acquisition, had net daily production of approximately 1,100 BOE/d.
- On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field located primarily around our existing Greeley and Windsor areas. The Bayswater Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The Bayswater acquisition provided net daily production of approximately 6,900 BOE/d.
- In 2015, we granted certain members of management incentive units pursuant to Holdings' 2014 Membership Unit Incentive Plan and its limited liability company agreement. These equity-based awards are subject to time-based vesting requirements, as well as accelerated vesting upon the occurrence of a change of control. In

connection with the IPO, the Board of Managers of Holdings accelerated the vesting of the Holdings' Incentive Units. Our IPO and change of control triggered the conversion of these units into approximately 9.1 million of our common shares based on the 10-day volume weighted average price of our common stock following its IPO as set forth in the 2014 Plan and the Holdings LLC Agreement. For the year ended December 31, 2016, we recognized approximately $172.1 million in non-cash, share-based compensation expense in connection with the conversion of the Holdings' Incentive Units into our common stock.

- In connection with the consummation of the IPO, we issued 185,280 shares of our Series A Preferred Stock to the holders of Holdings' Series B Preferred Units in conversion of such units. The Series A Preferred Stock are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are paid in cash).
- In connection with the consummation of the IPO, we expect to incur additional general and administrative expenses related to being a public company, including Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with listing on the NASDAQ; incremental independent auditor fees; incremental legal fees; investor relations expenses; registrar and transfer agent fees; incremental director and officer liability insurance costs; and directors compensation.
- In connection with the IPO, Holdings was merged into the Company. Prior to this corporate reorganization, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings' taxable income was passed through to our members. Beginning October 12, 2016, we began to be taxed as a C corporation under the Internal Revenue Code and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

The following table provides the components of our revenues, operating expenses, other income (expense) and net income (loss) for the periods indicated (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil sales	$ 194,059	$ 157,024	$ 75,460
Natural gas sales	48,652	26,019	9,247
NGL sales	35,378	14,707	8,133
Total Revenues	278,089	197,750	92,840
Operating Expenses:			
Lease operating expenses	62,043	30,628	5,067
Production taxes	20,730	17,035	9,743
Exploration expenses	36,422	18,636	126
Depletion, depreciation, amortization and accretion	205,348	146,547	34,042
Impairment of long lived assets	23,425	15,778	—
Other operating expenses	10,891	2,353	—
Acquisition transaction expenses	2,719	6,000	—
General and administrative expenses	232,388	37,149	19,598
Total Operating Expenses	593,966	274,126	68,576
Operating Income (Loss)	(315,877)	(76,376)	24,264
Other Income (Expense):			
Commodity derivatives gain (loss)	(100,947)	79,932	48,008
Interest expense	(68,843)	(51,030)	(22,454)
Other income	386	210	24
Total Other Income (Expense)	(169,404)	29,112	25,578
Net Income (Loss) Before Income Taxes	(485,281)	(47,264)	49,842
Income Tax Benefit	29,280	—	—
Net Income (Loss)	$ (456,001)	$ (47,264)	$ 49,842

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	For the Year Ended December 31,		
	2016	2015	2014
Sales (MBoe)[1]:	10,940.0	7,084.0	1,791.5
Oil sales (MBbl)	5,287.4	3,945.6	1,022.2
Natural gas sales (MMcf)	20,211.5	10,823.0	2,664.1
NGL sales (MBbl)	2,284.0	1,334.6	325.3
Sales (BOE/d)[1]:	29,891	19,408	4,908
Oil sales (Bbl/d)	14,446	10,810	2,801
Natural gas sales (Mcf/d)	55,223	29,652	7,299
NGL sales (Bbl/d)	6,240	3,656	891
Average sales prices[2]:			
Oil sales (per Bbl)	$ 36.70	$ 39.80	$ 73.82
Oil sales with derivative settlements (per Bbl)	40.59	53.29	77.66
Natural gas sales (per Mcf)	2.41	2.40	3.47
Natural gas sales with derivative settlements (per Mcf)	2.81	2.82	3.49
NGL sales (per Bbl)	15.49	11.02	25.00
Average price per BOE	25.42	27.92	51.82
Average price per BOE with derivative settlements	28.04	36.06	54.04
Expense per BOE:			
Lease operating expenses	$ 5.67	$ 4.32	$ 2.83
Operating expenses	3.36	3.39	2.83
Transportation and gathering [3]	2.31	0.93	—
Production taxes	1.89	2.40	5.44
Exploration expenses	3.33	2.63	0.07
Depletion, depreciation, amortization, and accretion	18.77	20.69	19.00
Impairment of long lived assets	2.14	2.23	—
Other operating expenses [4]	1.00	0.33	—
Acquisition transaction expenses	0.25	0.85	—
General and administrative expenses	21.24	5.24	10.94
Cash general and administrative expenses	2.93	4.40	8.45
Unit and stock-based compensation	18.31	0.84	2.49
Total operating expenses per BOE	54.29	38.69	38.28

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

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

(3) During the year ended December 31, 2014, the Company did not separately track transportation and gathering charges, which are included in LOE.

(4) During the year ended December 31, 2016, the Company wrote off the $10.0 non-refundable deposit associated with the option to acquire additional assets from the October 2016 Acquisition.

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

Oil sales revenues. Crude oil sales revenues increased by $37.1 million to $194.1 million for the year ended December 31, 2016 as compared to crude oil sales of $157.0 million for the year ended December 31, 2015. An increase in sales volumes between these periods contributed a $53.4 million positive impact, while a decrease in crude oil prices contributed a $16.3 million negative impact.

For the year ended December 31, 2016, our crude oil sales averaged 14.4 MBbl/d. Our crude oil sales volume increased 34% to 5,287.4 MBbl in the year ended December 31, 2016 compared to 3,945.6 MBbl for the year ended December 31, 2015. The volume increase was primarily due to the development of our properties. For the year ended

December 31, 2016, we completed 72 gross wells. Offsetting the increased production from these new wells was the normal decline on the existing producing properties.

The average price we realized on the sale of crude oil was $36.70 per Bbl for the year ended December 31, 2016 compared to $39.80 per Bbl for the year ended December 31, 2015.

Natural gas sales revenues. Natural gas sales revenues increased by $22.7 million to $48.7 million for the year ended December 31, 2016 as compared to natural gas sales revenues of $26.0 million for the year ended December 31, 2015. An increase in sales volumes between these periods contributed $22.7 million positive impact, while the change in natural gas prices had a de minimis impact.

For the year ended December 31, 2016, our natural gas sales averaged 55.2 MMcf/d. Natural gas sales volumes increased by 87% to 20,211.5 MMcf for the year ended December 31, 2016 as compared to 10,823.0 MMcf for the year ended December 31, 2015. The volume increase was primarily due to the development of our properties. For the year ended December 31, 2016, we completed 72 gross wells. Offsetting the increased production from these new wells was the normal decline on the existing producing properties.

The average price we realized on the sale of our natural gas was $2.41 per Mcf for the year ended December 31, 2016 compared to $2.40 per Mcf for the year ended December 31, 2015.

NGL sales revenues. NGL revenues increased by $20.7 million to $35.4 million for the year ended December 31, 2016 as compared to NGL revenues of $14.7 million for the year ended December 31, 2015. An increase in sales volumes between these periods contributed a $10.5 million positive impact, while an increase in price contributed a $10.2 million positive impact.

For the year ended December 31, 2016, our NGL sales averaged 6.2 MBbl/d. NGL sales volumes increased by 71% to 2,284.0 MBbl for the year ended December 31, 2016 as compared to 1,334.6 MBbl for the year ended December 31, 2015. The volume increase was due to the development of our properties. Our NGL sales are directly associated with our natural gas sales since the majority of our natural gas volumes are processed by third parties which return a percentage of the proceeds from both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $15.49 per Bbl for the year ended December 31, 2016 compared to $11.02 per Bbl for the year ended December 31, 2015.

Lease operating expenses. Our LOE, increased by $31.4 million to $62.0 million for the year ended December 31, 2016, from $30.6 million for the year ended December 31, 2015. The increase in LOE was comprised of an increase in transportation and gathering ("T&G") expense of $18.7 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 and an increase in operating expenses of $12.7 million for the year ended December 31, 2016 compared to the year ended December 31, 2015.

On a per unit basis, LOE, increased $1.35 per BOE from $4.32 per BOE sold for the year ended December 31, 2015 to $5.67 per BOE sold for the year ended December 31, 2016. The increase was comprised of an increase in T&G expense of $1.38 per BOE from $0.93 per BOE for the year ended December 31, 2015 to $2.31 per BOE for the year ended December 31, 2016. The increase in T&G per BOE was offset by a decrease in operating expenses of $0.03 per BOE from $3.39 per BOE for the year ended December 31, 2015 to $3.36 per BOE for the year ended December 31, 2016. The increase in LOE was primarily the result of an increase in T&G fees on gas sales as a result of the Company entering into more fee-type gas transportation contracts versus percent of proceeds gas transportation contracts.

Production taxes. Our production taxes increased by $3.7 million to $20.7 million for the year ended December 31, 2016 as compared to $17.0 million for the year ended December 31, 2015. The increase was attributable to increased revenue as State of Colorado production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 7.5% for the year ended December 31, 2016 as compared to 8.6% for the year ended December 31, 2015. Production tax rates can vary depending on the location and the volumes produced from our properties.

Exploration expenses. Our exploration expenses were $36.4 million and $18.6 million for the years ended December 31, 2016 and 2015. We recognized $14.1 million in expense attributable to the extension of leases and

$22.3 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2016. We recognized $2.2 million in expense attributable to the extension of leases and $16.4 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2015.

Depletion, depreciation, amortization and accretion expense ("DD&A"). Our DD&A expense increased $58.8 million to $205.3 million for the year ended December 31, 2016 as compared to $146.5 million for the year ended December 31, 2015. This increase was due to higher volumes sold for the year ended December 31, 2016 as sales increased by approximately 3,856.0 MBoe. On a per unit basis, DD&A expense decreased from $20.69 per BOE for the year ended December 31, 2015 to $18.77 per BOE for the year ended December 31, 2016.

Impairment of long lived assets. For the year ended December 31, 2016, we recognized $22.5 million in impairment expense on proved oil and gas properties in our northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in our northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016. Additionally, for the year ended December 31, 2016 we recognized $0.9 million of impairment on other property and equipment. During 2015, we sold proved oil and gas properties for proceeds of $4.7 million. In connection with the sale, we determined that assets' net book value exceeded the fair value of such properties by $2.7 million. We recognized that amount as an impairment expense for the year ended December 31, 2015. During 2015, we also recorded impairment expense of $9.5 million related to impairment of a subsidiary. Our subsidiary had negative future undiscounted cash flows associated with its proved oil and gas properties as of December 31, 2015, and it was determined that our subsidiary's proved oil and gas properties had no remaining fair value. Therefore, our subsidiary's full net book value of proved oil and gas properties were impaired. Additionally, we recognized $3.6 million in impairment expense related to a specifically proposed gas processing plant that is no longer being pursued.

Other operating expenses. Other operating expenses for the year ended December 31, 2016 includes $10.0 million on the write off of a non-refundable payment related to an option to acquire additional acreage. In March 2017, we entered into an amendment to this agreement with Bayswater to terminate both our and Bayswater's options for no further consideration. Also included in other operating expenses for the year ended December 31, 2016 is a $0.9 million rig termination fee related to the early termination of a rig in February 2016. Other operating expenses for the year ended December 31, 2015 were comprised of a $1.7 million rig termination fee related to the early termination of a rig in March 2015 and a rig standby fee of $0.7 million in September 2015.

Acquisition transaction expenses. As part of the acquisition of properties in August 2016 and October 2016, respectively, we incurred $2.7 million of transaction costs associated with a finder's fee, legal expense and due diligence for the year ended December 31, 2016. For the year ended December 31, 2015, we incurred $6.0 million of non-cash transaction costs associated with a finder's fee to an unaffiliated third-party as part of the acquisition of properties in March 2015. We assigned an over-riding royalty interest in the proved and unproved oil and gas properties acquired in March 2015, which had a fair value of $6.0 million on the measurement date, as payment for the finder's fee.

General and administrative expenses ("G&A"). General and administrative expenses increased by $195.3 million to $232.4 million for the year ended December 31, 2016 as compared to $37.1 million for the year ended December 31, 2015. This increase was comprised of an increase in unit and stock-based compensation of $194.3 million and an increase in other general and administrative expenses of $1.0 million. On a per unit basis, G&A expenses increased from $5.24 per BOE sold for the year ended December 31, 2015 to $21.24 per BOE sold for the year ended December 31, 2016.

Our G&A expenses includes the non-cash expense for unit and stock-based compensation for equity awards granted to our employees and non-employee consultants. For the year ended December 31, 2016, unit and stock-based compensation expense was $200.3 million as compared to $6.0 million for the year ended December 31, 2015. On a per unit basis, unit and stock-based compensation increased $17.47 per BOE from $0.84 per BOE sold for the year ended December 31, 2015 to $18.31 per BOE sold for the year ended December 31, 2016. The increase in unit and stock-based compensation expense was due to accelerated vesting of outstanding Holdings RUAs in connection with our Corporate Reorganization and IPO. Additionally, as a result of the IPO, Holdings incentive units were converted to common stock resulting in $172.1 million of stock-based compensation expense. Also, we created a Long Term Incentive Plan, which resulted in the granting of RSUs and stock options to certain board members, officers, and employees.

Our other G&A expenses increased by $1.0 million during the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to the growth of the Company, however on a per BOE basis, other G&A expenses per BOE sold decreased $1.47 per BOE sold from $4.40 per BOE sold for the year ended December 31, 2015 to $2.93 per BOE sold for the year ended December 31, 2016. The decrease in other G&A expenses on a per BOE basis is due to increases in production volumes for the year ended December 31, 2016.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at December 31, 2016 as compared to December 31, 2015 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $100.9 million for the year ended December 31, 2016. Primarily due to the decrease in NYMEX crude oil futures prices at December 31, 2015 as compared to December 31, 2014 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $79.9 million for the year ended December 31, 2015. These losses and gains are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. For the years ended December 31, 2016 and 2015, we received cash settlements of commodity derivatives totaling $34.2 million and $59.8 million, respectively.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the year ended December 31, 2016, we recognized interest expense of approximately $68.8 million as compared to $51.0 million for the year ended December 31, 2015, as a result of borrowings under our revolving credit facility, borrowings on our Second Lien Notes, our Senior Notes and the amortization of remaining unamortized debt issuance costs and debt discount upon the repayment of our Second Lien Notes.

We incurred interest expense the year ended December 31, 2016 of approximately $50.5 million related to our revolving credit facility, our Senior Notes in 2016 and our Second Lien Notes. Interest expense for the year ended December 31, 2016 included the accelerated amortization of our remaining unamortized debt discount and debt issuance costs of $15.1 million upon the repayment of our Second Lien Notes in July 2016, and the amortization of debt issuance costs on our Second Lien Notes, Senior Notes and credit facility of $4.2 million, excluding the accelerated amortization of the remaining unamortized debt discount and debt issuance costs on our Second Lien Notes. Also included in interest expense for the year ended December 31, 2016 was a prepayment penalty in the amount of $4.3 million incurred upon the repayment of our Second Lien Notes. Interest expense for the year ended December 31, 2015 includes $50.7 million of interest expense related to our revolving credit facility and Second Lien Notes and the amortization of debt discount and debt issuance costs of $5.6 million. For the years ended December 31, 2016 and 2015, we capitalized interest expense of $5.2 million and $5.3 million, respectively.

Income tax benefit. We recorded an income tax benefit for the year ended December 31, 2016 of $29.3 million, resulting in effective tax rate of approximately 6%. Our effective tax rate for 2016 differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes, permanent taxable differences and the Corporate Reorganization. Nondeductible stock compensation expense made up the majority of the permanent items which related to the conversion of incentive units to common stock. See *Note 11 — Unit and Stock-Based Compensation* in the notes to our consolidated financial statements for additional discussion of Holdings' Incentive Units. Prior to the Corporate Reorganization we were organized as a limited liability company that was not subject to U.S. federal income tax. Excluding the impact of the Corporate Reorganization and nondeductible stock compensation, our overall effective tax rate was 35%. For 2016, our combined federal and state statutory tax rate was 38%.

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

Oil sales revenues. Crude oil sales revenues increased by $81.6 million to $157.0 million for the year ended December 31, 2015 as compared to crude oil sales of $75.5 million for the year ended December 31, 2014. An increase in sales volumes between these periods contributed a $215.8 million positive impact, which was partially offset by a $134.2 million negative impact due to declining crude oil prices.

For the year ended December 31, 2015, our crude oil sales averaged 10.8 MBbls/d. Our crude oil sales volume increased 286% to 3,945.6 MBbls in the year ended December 31, 2015 compared to 1,022.2 MBbls in the year ended

December 31, 2014. The volume increase was due to the development of our properties as well as our acquisitions during 2015 and 2014. Of the 2,923.4 MBbls increase in crude oil sales volume, 651.9 MBbls was related to the increase in production from producing wells acquired and 2,271.5 MBbls is attributed to our ongoing development of our properties and undeveloped acreage.

The average price we realized on the sale of crude oil was $39.80 per Bbl for the year ended December 31, 2015 compared to $73.82 per Bbl for the year ended December 31, 2014.

Natural gas sales revenues. Natural gas revenues increased by $16.8 million to $26.0 million for the year ended December 31, 2015 as compared to natural gas revenues of $9.2 million for the year ended December 31, 2014. An increase in sales volumes between these periods contributed a $28.3 million positive impact, which was partially offset by an $11.5 million negative impact due to declining natural gas prices.

For the year ended December 31, 2015, our natural gas sales averaged 29.7 MMcf/d. Natural gas sales volumes increased by 306% to 10,823.0 MMcf for the year ended December 31, 2015 as compared to 2,664.1 MMcf for the year ended December 31, 2014. The volume increase was due to the development of our properties as well as our acquisitions during 2015 and 2014. Of the 8,158.9 MMcf increase in natural gas sales volume, 3,072.5 MMcf was related to the increase in production from producing wells acquired and 5,086.4 MMcf was attributed to our ongoing development of our properties and undeveloped acreage.

The average price we realized on the sale of our natural gas was $2.40 per Mcf for the year ended December 31, 2015 compared to $3.47 per Mcf for the year ended December 31, 2014.

NGL sales revenues. NGL revenues increased by $6.6 million to $14.7 million for the year ended December 31, 2015 as compared to NGL revenues of $8.1 million for the year ended December 31, 2014. An increase in sales volumes between these periods contributed a $25.2 million positive impact, which was offset by an $18.6 million negative impact due to declining NGL prices.

For the year ended December 31, 2015, our NGL sales averaged 3.7 Bbl/d. NGL sales volumes increased by 310% to 1,334.6 MBbls for the year ended December 31, 2015 as compared to 325.3 MBbls for the year ended December 31, 2014. The volume increase was due to the development of our properties as well as our acquisitions during 2015 and 2014. Our NGL sales are directly associated with our natural gas sales since the majority of our natural gas volumes are processed by third parties which return a percentage of the proceeds from both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $11.02 per Bbl in the year ended December 31, 2015 compared to $25.00 per Bbl in the year ended December 31, 2014.

Lease operating expenses Our LOE (including transportation and gathering expense) increased by $25.6 million to $30.6 million for the year ended December 31, 2015, from $5.1 million for the year ended December 31, 2014.

On a per unit basis, LOE increased from $2.83 per BOE sold for the year ended December 31, 2014 to $4.32 per BOE sold for the year ended December 31, 2015. The increase was primarily the result of the acquisition of properties in March 2015, which included older vertical wells that have higher cost, on a per BOE sold basis, than our newer horizontal wells. As wells mature, we expect to incur additional costs to put these wells on artificial lift, which increases costs in fuel, electricity and related expenses.

Production taxes. Our production taxes increased by $7.3 million to $17.0 million for the year ended December 31, 2015 as compared to $9.7 million for the year ended December 31, 2014. The increase was attributable to increased revenue as State of Colorado production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.6% for the year ended December 31, 2015 as compared to 10.5% for the year ended December 31, 2014.

Exploration expenses. Our exploration expenses were $18.6 million for the year ended December 31, 2015. We recognized $16.4 million in impairment expense attributable to the abandonment and impairment of unproved properties and $2.2 million for extensions on leases for the year ended December 31, 2015. For the year ended

December 31, 2014, there were no significant exploration expenses or abandonment and impairment of unproved properties.

Depletion, depreciation, amortization and accretion expense Our DD&A expense increased $112.5 million to $146.5 million for the year ended December 31, 2015 as compared to $34.0 million for the year ended December 31, 2014. This increase was due to higher volumes sold for the year ended December 31, 2015 as sales increased by approximately 5,292.4 MBoe. On a per unit basis, DD&A expense increased from $19.00 per BOE for the year ended December 31, 2014 to $20.69 per BOE for the year ended December 31, 2015.

Impairment of long lived assets. During 2015, we sold proved oil and gas properties for proceeds of $4.7 million. In connection with the sale, we determined that assets' net book value exceeded the fair value of such properties by $2.7 million. We recognized that amount as an impairment expense for the year ended December 31, 2015. During 2015, we also recorded impairment expense of $9.5 million related to impairment of a subsidiary. Our subsidiary had negative future undiscounted cash flows associated with its proved oil and gas properties as of December 31, 2015, and it was determined that our subsidiary's proved oil and gas properties had no remaining fair value. Therefore, our subsidiary's full net book value of proved oil and gas properties were impaired. Additionally, we recognized $3.6 million in impairment expense related to a specifically proposed gas processing plant that is no longer being pursued.

Other operating expenses. Other operating expenses for the year ended December 31, 2015 were comprised of a $1.7 million rig termination fee related to the early termination of a rig in March 2015 and $0.7 million related to rig standby fees in September 2015. There were no other operating expenses for the year ended December 31, 2014.

Acquisition transaction expenses. As part of the acquisition of properties in March 2015, we incurred $6.0 million of non-cash transaction costs associated with a finder's fee to an unaffiliated third-party. We assigned an overriding royalty interest in the proved and unproved oil and gas properties acquired in March 2015, which had a fair value of $6.0 million on the measurement date. For the year ended December 31, 2014, we did not recognize any non-cash acquisition transaction expenses.

General and administrative expenses G&A expense increased by $17.6 million to $37.1 million for the year ended December 31, 2015 as compared to $19.6 million for the year ended December 31, 2014. This increase was due to the growth in personnel and related costs as we have expanded our operational activities. On a per unit basis, G&A expense decreased from $10.94 per BOE sold for the year ended December 31, 2014 to $5.24 per BOE sold in the year ended December 31, 2015. The decrease was primarily due to our increase in sales volumes from our acquisitions and our ongoing development program.

Our G&A expense includes the non-cash expense for unit-based compensation for equity awards granted to our employees and non-employee consultants. For the year ended December 31, 2015, unit-based compensation expense was $6.0 million as compared to $4.5 million for the year ended December 31, 2014.

Commodity derivative gain. We began using commodity derivatives in September 2014. Primarily due to the decrease in NYMEX crude oil futures prices at December 31, 2015 as compared to December 31, 2014, we incurred a net gain on our commodity derivatives of $79.9 million for the year ended December 31, 2015. This gain was a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. During the years ended December 31, 2015 and 2014, we received cash settlements of commodity derivatives totaling $59.8 million and $4.0 million, respectively.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the year ended December 31, 2015, we recognized interest expense of approximately $51.0 million as compared to $22.5 million for the year ended December 31, 2014, as a result of borrowings under our revolving credit facility and our Second Lien Notes.

We incurred interest expense for the years ended December 31, 2015 and 2014 of approximately $50.7 million and $23.1 million, respectively, related to our revolving credit facility and our Second Lien Notes. Also included in interest expense for the years ended December 31, 2015 and 2014 was the amortization of debt issuance costs and debt discount of $4.2 million and $2.0 million, respectively. Additionally, during 2015, we incurred $1.4 million related to a potential financing transaction, and we recorded such amount as amortization expense for the year ended December 31,

2015. For the years ended December 31, 2015 and 2014, we capitalized interest costs of $5.3 million and $2.6 million, respectively.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. Depending upon market conditions and other factors, we may also issue equity and debt securities if needed.

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, our Second Lien Notes, our Senior Notes (please refer to *Note 5 — Long Term Debt)*, equity provided by investors, including our management team, cash from the IPO and Private Placement and cash flows from operations. To date, our primary use of capital has been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt discount and debt issuance costs, were approximately $538.1 million and $637.8 million at December 31, 2016, and December 31, 2015, respectively. We also have other contractual commitments, which are described in *Note 13 — Commitments and Contingencies.*

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 80% of our projected oil and natural gas production over a one-to-two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program, excluding any acquisitions we may consummate, make our interest payments on the Senior Notes and pay dividends on our Series A Preferred Stock.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, 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 proved reserves.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program.

Cash Flows

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

	For the Year Ended December 31,		
	2016	2015	2014
		(in thousands)	
Net cash provided by operating activities	$ 116,388	$ 166,683	$ 77,390
Net cash used in investing activities	(915,808)	(520,006)	(970,640)
Net cash provided by financing activities	1,291,050	371,404	972,090

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

Net cash provided by operating activities. For the year ended December 31, 2016 as compared to the year ended December 31, 2015, our net cash provided by operating activities decreased by $50.3 million, primarily due to a decrease in changes in current assets and liabilities of $59.6 million, along with a decrease in cash settlements, including changes to accounts receivable and accounts payable on commodity derivatives of $12.9 million. These decreases were offset by an increase in sales volume of 3,856.0 MBOE and the associated increase in revenue less operating expenses.

Net cash used in investing activities. For the year ended December 31, 2016 as compared to the year ended December 31, 2015, our net cash used in investing activities increased by $395.8 million primarily due to $298.5 million in additional acquisition of properties, an increase of $52.3 million in cash held in escrow for acquisitions as required under the related purchase and sale agreements, and a reduction of cash received from the sale of property and equipment of $2.0 million in 2016 compared to 2015. Additionally, there was an increase of $43.0 million in cash expended for drilling and completion activities and other property and equipment for the year ended December 31, 2016 as compared to the year ended December 31, 2015.

Net cash provided by financing activities. For the year ended December 31, 2016 as compared to the year ended December 31, 2015, our net cash provided by financing activities increased by $919.6 million, primarily as a result of an increase of $990.0 million in proceeds from the issuance of common stock and members units, net of issuance costs in the year ended December 31, 2016 compared to December 31, 2015. Additionally, we issued preferred equity securities, net of repayments and dividends, in the amount of $170.8 million. These increases were offset by an increase of $241.2 million in the net repayment of debt due to the repayment of our credit facility and Second Lien Notes during the year ended December 31, 2016 with proceeds from our Senior Notes and IPO.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Net cash provided by operating activities. For the year ended December 31, 2015 as compared to the year ended December 31, 2014, our net cash provided by operating activities increased by $89.3 million, primarily due to an increase in sales volumes of approximately 5,292.4 MBoe.

Net cash used in investing activities. For the year ended December 31, 2015 as compared to the year ended December 31, 2014, our net cash used in investing activities decreased by $450.6 million primarily due to a decrease of $586.8 million used in acquisitions. Partially offsetting this decrease was an increase of $150.8 million in cash expended for drilling and completion activities.

Net cash provided by financing activities. For the year ended December 31, 2015 as compared to the year ended December 31, 2014, our net cash provided by financing activities decreased by $600.7 million, primarily as a result of a decrease in proceeds received from the issuance of units of $220.4 million. Additionally, this decrease was partially due to a decrease of $398.5 million in borrowings under our revolving credit facility and our second lien notes. Offsetting these decreases was an $18.2 million decrease in cash used for debt and equity issuance costs for the year ended December 31, 2015 compare to the year ended December 31, 2014.

Working Capital

Our working capital surplus was $379.1 million and $47.5 million at December 31, 2016 and 2015, respectively. Our cash balances totaled $588.7 and $97.1 million at December 31, 2016 and December 31, 2015, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility after application of the net proceeds from the IPO and the Private Placement 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, natural gas and NGL production will be the largest variables affecting our working capital.

Debt Arrangements

Our revolving credit facility has a maximum credit amount of $1 billion, subject to a borrowing base, and all of our current and future subsidiaries will be guarantors under such facility. Amounts repaid under our revolving credit facility may be re-borrowed from time to time, subject to the terms of the facility. For more information on the revolving credit facility, please see *Note 5 — Long-Term Debt* in Item 8. Financial Statements and Supplementary Data of this Annual Report. The revolving credit facility is secured by liens on substantially all of our properties.

On May 29, 2014, we entered into a second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and a syndicate of lenders for the Second Lien Notes with an aggregate principal amount equal to $430.0 million. The full balance was repaid in July 2016 with proceeds from our Senior Notes Offering.

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.2 million. Our Senior Notes bear interest at an annual rate of 7.875%. Interest on our Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our Senior Notes will mature on July 15, 2021. A portion of the proceeds of the 2016 Notes Offering was used to repay all of the outstanding borrowings and related premium, fees and expenses under our second lien notes and terminate such notes, and the remaining proceeds were used to repay borrowings under our revolving credit facility and for general business purposes, including acquisitions. Our Senior Notes are guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes).

Revolving Credit Facility

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under our revolving credit facility. As of December 31, 2016, the borrowing base was $475.0 million, and there were no borrowings outstanding under our revolving credit facility.

Principal amounts borrowed will be payable on the maturity date, and interest will be payable quarterly for alternate base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the product of: (a) the LIBOR rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the reserve percentages (expressed as a decimal) on such date at which the administrative agent under our revolving credit facility is required to maintain reserves on 'Eurocurrency Liabilities' as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted one-month LIBOR rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. As of December 31, 2016, we had no outstanding borrowings under our revolving credit facility. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The revolving credit facility is secured by liens on substantially all of our properties and guarantees from us and our current and future subsidiaries. The revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- make certain changes to our capital structure;

- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with our affiliates;
- holding cash balances in excess of certain thresholds while carrying a balance of our revolving credit facility;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The revolving credit facility requires us to maintain the following financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, the second lien notes and certain derivative assets), of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a maximum leverage ratio, which is the ratio of (i) consolidated debt less cash balances in excess of certain thresholds to (ii) our consolidated EBITDAX for the four fiscal quarter period most recently ended, not to exceed 4.0 to 1.0 as of the last day of such fiscal quarter; *provided that* (a) for the quarters ending between December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and (b) for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3, and (c) for the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX.

Senior Notes

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.2 million. Our Senior Notes bear interest at an annual rate of 7.875%. Interest on our Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our Senior Notes will mature on July 15, 2021.

We may, at our option, redeem all or a portion of our Senior Notes at any time on or after July 15, 2018. We are also entitled to redeem up to 35% of the aggregate principal amount of our Senior Notes before July 15, 2018, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.875% of the principal amount of our Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to July 15, 2018, we may redeem some or all of our Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium. If we experience certain kinds of changes of control, holders of our Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes) that guarantees our indebtedness under a credit facility. The notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the notes.

Convertible Preferred Securities

We previously issued to affiliates of Apollo $75.0 million in Series A Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. We used $90.0 million of the net proceeds from the IPO to redeem the Series A Preferred Units in full, which included a premium of $15.0 million.

In addition, we issued to, among others, investment funds affiliated with OZ Management LP and Yorktown $185.3 million in Series B Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and we had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units were converted in connection with the closing of the IPO into shares of our Series A Preferred Stock that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). Beginning on or after the later of (a) 90 days after the closing of the IPO and (b) the Lock-Up Period End Date, the Series A Preferred Stock will be convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the IPO, we may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. See *Note 9 — Members' and Stockholders' Equity— Series A Preferred Stock and Series B Preferred Units"* in Item 8. Financial Statements and Supplementary Data of this Annual Report.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2016 is provided in the following table (in thousands).

	Payments due by Period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
			(In thousands)		
Contractual Obligations					
Office lease[1]	$ 21,117	$ 2,492	$ 4,943	$ 4,141	$ 9,541
Drilling rig obligations[2]	4,973	600	3,885	488	—
Volume commitment[3][4]	951,243	74,281	189,343	202,703	484,916
Revolving credit facility and interest payable[5]	3,405	1,779	1,626	—	—
Senior Notes and Interest Payable[6]	766,202	42,952	86,625	636,625	—
Total	$ 1,746,940	$ 122,104	$ 286,422	$ 843,957	$ 494,457

(1) We lease two office spaces in Denver, Colorado, one office space in Greeley, Colorado and one office space in Houston, Texas under four separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2026. The Greeley, Colorado and Houston, Texas leases expire on August 19, 2019 and October 31, 2017, respectively. Total rental commitments under non-cancelable leases for office space were $21.1 million at December 31, 2016.

(2) As of December 31, 2016, we were subject to commitments on four drilling rigs. Two drilling rigs are under contract and are set to expire on May 30, 2017 and July 24, 2017. Remaining two drilling rigs are under contract on a month-to-month basis, subject to each party's right to terminate upon 30 and 60 days' notice. The Company provided notice for termination on one drilling rig on January 6, 2017 and paid no termination fees. Additionally, in January 2017, the Company entered into an additional commitment on an additional drilling rig, which is anticipated to be placed in service during the third quarter of 2017. In the event of early termination on this contract the Company would be obligated to pay an aggregate amount of approximately $5.7 million, as required under the terms of the contracts. This additional rig commitment entered into in January 2017 is not included in the table above.

(3) As of December 31, 2016, the Company's oil marketer was subject to a firm transportation agreement that commended in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven, and 58,000 Bbl/d in years eight through ten and any failure to satisfy the minimum volume commitments is taken into account when calculating the revenue we receive from the oil marketer. The Company also had two long-term crude oil gathering commitments. The first has a term of five years for 5,000 Bbl/d in year one and 3,800 Bbl/d in years two through five and the second has a term of seven years for 4,000 Bbl/d in years one through three, 2,500 Bbl/d in year four, and 1,500 Bbl/d in years five through seven. The aggregate amount of estimated payments under these agreements was $951.2 million.

(4) In collaboration with several other producers and DCP Midstream, we have entered into an agreement that requires us to deliver minimum amounts of natural gas under certain circumstances. Our share of the commitment would require 51.5 MMcf of natural gas per day for a period of 7 years from the plant in-service date, which is currently expected to be in late 2018. We may be required to pay penalties or damages pursuant to this agreement if we are unable to fulfill our contractual obligation from our own production and if the collective volumes delivered by other producers in the DJ Basin are not in excess of the total commitment. Our volume shortfall fee would range between $0.95 and $1.50 per Mcf, in the event we do not meet our minimum volume commitment per month. At this time, we are unable to reasonably estimate potential volume shortfalls due to the volume pooling with other producers in the DJ Basin, and they have therefore not been reflected in the table above.

(5) Calculated based on no outstanding borrowings under our revolving credit facility as of December 31, 2016 and assumes no borrowings until the maturity date of the notes. Interest on our revolving credit facility is payable at one of the following two variable rates as selected by us: a base rate based on the Prime Rate or the Eurodollar rate based in LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the Pricing Grid. Additionally, our revolving credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage.

(6) Calculated based on December 31, 2016 outstanding aggregate principal amount on our Senior Notes of $550.0 million outstanding, at a fixed interest rate of 7.875%, Interest is payable on our Senior Notes on a semi-annual basis through the maturity date of July 15, 2021.

The above contractual obligations schedule does not include the Series A Preferred Stock, future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the timing of such payments. For further discussion regarding our derivative contracts and estimated future costs associated with the abandonment of our oil and gas properties, please refer to *Note 9 — Members' and Stockholders' Equity, Note 6 — Commodity Derivative Instruments* and *Note 7 — Asset Retirement Obligations* of our historical audited financial statements for the years ended December 31, 2016 and 2015. Additionally, for further information regarding our contractual obligations as of December 31, 2016, please refer to *Note 13 — Commitments and Contingencies* to our historical unaudited financial statements for the year ended December 31, 2016 and 2015.

As is customary in the oil and gas industry, we may at times have commitments in place to reserve or earn certain acreage positions or wells. If we do not meet such commitments, the acreage positions or wells may be lost or we may be required to pay damages if certain performance conditions are not met.

Off-Balance Sheet Arrangements

Currently, we do not have any material off-balance sheet arrangements.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to decline commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the years ended December 31, 2014 and 2015, commodity prices decreased, while during the year ended December 31, 2016, commodity prices increased. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

Critical Accounting Policies and Estimates

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties; (3) depreciation, depletion, amortization and accretion; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of unit and stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. We evaluate our estimates on an on-going basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe our estimates are reasonable.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

Oil and Gas Reserves

Our estimates of proved reserves are based on the 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 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. Our independent petroleum engineers, Ryder Scott, prepare a reserve and economic evaluation of all of our properties on a well-by-well basis. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;

- interpretation of that data;
- accuracy of various mandated economic assumptions; and
- judgment of the independent reserve engineer.

One of the most significant estimates we make is the estimate of oil, natural gas and NGL reserves. Oil, natural gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, our DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of oil and gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. We cannot predict what reserve revisions may be required in future periods.

Ryder Scott estimated all of our proved reserve quantities as of December 31, 2016, 2015 and 2014. In connection with Ryder Scott performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Year Ended December 31,		
	2016	2015	2014
Revisions resulting from price changes (MBOE)	(6,666)	(48,578)	1
Revisions resulting from production and performance (MBOE)	(955)	47,428	1,037
Total revisions (MBOE)	(7,621)	(1,150)	1,038

The recent significant decline in oil, natural gas and NGL prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs.

Depreciation, Depletion, Amortization and Accretion.

Our DD&A rate is dependent upon our estimates of total proved and proved developed reserves, which incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Proved Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and 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 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, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization.

For the year ended December 31, 2016, we recognized $22.5 million in impairment expense on proved oil and gas properties in the our northern field. For the year ended December 31, 2015, we recognized $9.5 million in impairment expense on proved oil and gas properties in our northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in our northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015. In December 2015, we sold proved oil and gas properties for proceeds of $4.7 million. As result, these assets were fair valued on the date of the transaction in accordance with ASC 360, *Property, Plant and Equipment*. The net book value of these assets exceeded the fair value by $2.7 million, which we recognized as impairment expense. We recognized a total of $12.2 million in impairment expense attributable to proved oil and gas properties for the year ended December 31, 2015. No impairment expense was recognized attributable to proved oil and gas properties for the year ended December 31, 2014.

Our impairment analyses requires us to apply judgment in identifying impairment indicators and estimating future cash flows of our oil and gas properties. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

Forward commodity prices and estimates of future production also play a significant role in determining impairment of proved oil and gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and gas properties for impairment. At December 31, 2015, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately $800.0 million, or 74%. At December 31, 2016, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately $1.7 billion, or 108%. The key assumptions used to determine the undiscounted future cash flows include estimates of future production, future commodity pricing, differentials, net estimated operating costs, anticipated capital expenditures and new wells on production. Future commodity pricing for oil and NGLs is based on five-year West Texas Intermediate strip prices, which increased 16% from an average of $48.40/Bbl at December 31, 2015 to an average of $56.23/Bbl at December 31, 2016, and on five-year Henry Hub strip prices, which increased 14% from an average of $2.70/MMBtu at December 31, 2015 to an average of $3.08/MMBtu at December 31, 2016.

Impairment of Unproved Oil and Gas Properties

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. We evaluate significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, we recognized $22.3 million and $16.4 million in impairment expense for the years ended December 31, 2016 and 2015, respectively. No impairment expense was recognized attributable to unproved oil and gas properties for the year ended December 31, 2014.

Goodwill and Other Intangible Assets

We account for goodwill and other intangible assets under the provisions of the ASC 350, *Intangibles-Goodwill and Other*. Our goodwill represents the excess of the purchase price over the fair value of net identifiable assets acquired in a business combination. Goodwill is not amortized and is tested for impairment annually on September 30 or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. When evaluating goodwill for impairment, we may first perform an assessment of qualitative factors to determine if the fair value of the reporting unit is more-likely-than-not greater than its carrying amount. If, based on the review of the qualitative factors, we determine it is not more-likely-than-not that the fair value of a reporting unit is less than its carrying value, the required two-step can be bypassed. If we do not perform a qualitative assessment or if the fair value of the reporting unit is not more-likely-than-not greater than its carrying value, we must perform the first step of the two-step impairment test and calculate the estimated fair value of the reporting unit. If the carrying value of the reporting unit exceeds the estimated fair value, there is an indication that impairment may exist, and the second step must be performed to measure the amount of impairment loss. The amount of impairment for goodwill is measured as the amount by which the carrying amount of the goodwill exceeds the implied fair value of the goodwill. We performed a qualitative assessment as of December 31, 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license.

Commodity Derivative Instruments

We have entered into commodity derivative instruments, as described below. We have utilized swaps, put options, and call options to reduce the effect of price changes on a portion of our future oil and natural gas production. A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of our use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit our ability to benefit from favorable price movements. We may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. We do not enter into derivative contracts for speculative purposes.

The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets. We have not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, we do not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivative gain (loss) line on the statements of operations. Our cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in our statements of cash flows.

Our valuation estimate takes into consideration the counterparties' credit worthiness, our credit worthiness, and the time value of money. The consideration of the factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Accounting for Business Combinations

We account for all of our business combinations using the purchase method, which is the only method permitted under FASB ASC 805*, Business Combinations*, and involves the use of significant judgment. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of gas, oil and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, when a discounted cash flow model is used, the discounted future net cash flows of probable and possible reserves are reduced by additional risk factors. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist of estimated future costs associated with the plugging and abandonment of oil, natural gas and NGL wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws, and applicable lease terms. The 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 as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate to be used; and inflation rates. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGL are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. We recognize revenues from the sale of oil, natural gas and NGL using the sales method of accounting, whereby revenue is recorded based on the our share of volume sold, regardless of whether we have taken our proportional share of volume produced. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. We receive payment one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10% change in our revenue accrual would have impacted total operating revenues by approximately $3.4 million and $1.6 million for the years ended December 31, 2016 and 2015, respectively.

Unit and Stock-Based Payments

We have granted restricted unit awards ("RUAs") to certain employees and nonemployee consultants, restricted stock awards ("RSUs") and stock option awards to certain employees, which therefore required us to recognize the expense in its financial statements. All unit and stock-based payments to employees are measured at fair value on the grant date and expensed over the relevant service period. Unit-based payments to nonemployees are measured at fair value at each financial reporting date and expensed over the period of performance, such that aggregate expense recognized is equal to the fair value of the restricted units on the date performance is completed. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. All unit and stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations. Please refer to *Note 11 — Unit and Stock-Based Compensation* for additional discussion on unit and stock-based payments.

Income Taxes

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

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

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company does not currently have uncertain tax positions.

Extraction Oil & Gas Holdings, LLC, the Company's accounting predecessor, was a limited liability company that was not subject to U.S. federal income tax.

Recent Accounting Pronouncements

Please refer to Recent Accounting Pronouncements in *Note 2 — Basis of Presentation and Significant Accounting Policies* in Part II, Item 8 of this Annual Report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE 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, natural gas and NGL 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 NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

The following tables present our derivative positions related to crude oil and natural gas sales in effect as of December 31, 2016:

	For the Three Months Ended							
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
NYMEX WTI[1] Crude Swaps:								
Notional volume (Bbl)	1,050,000	450,000	—	—	450,000	450,000	—	—
Weighted average fixed price ($/Bbl)	$ 43.11	$ 45.56	$ —	$ —	$ 55.94	$ 55.94	$ —	$ —
NYMEX WTI[1] Crude Sold Calls:								
Notional volume (Bbl)	200,000	1,300,000	2,250,000	2,250,000	1,000,000	900,000	750,000	750,000
Weighted average fixed price ($/Bbl)	$ 55.45	$ 54.31	$ 56.28	$ 56.51	$ 61.55	$ 62.28	$ 62.73	$ 62.73
NYMEX WTI[1] Crude Sold Puts:								
Notional volume (Bbl)	675,000	1,175,000	2,075,000	2,175,000	750,000	750,000	750,000	750,000
Weighted average purchased put price ($/Bbl)	$ 35.44	$ 36.62	$ 38.45	$ 38.38	$ 40.00	$ 40.00	$ 40.00	$ 40.00
NYMEX WTI[1] Crude Purchased Puts:								
Notional volume (Bbl)	200,000	1,300,000	2,250,000	2,250,000	900,000	900,000	750,000	750,000
Weighted average purchased put price ($/Bbl)	$ 48.75	$ 46.46	$ 47.84	$ 48.04	$ 50.00	$ 50.00	$ 50.00	$ 50.00
NYMEX HH[2] Natural Gas Swaps:								
Notional volume (MMBtu)	4,990,000	5,590,000	7,420,000	7,420,000	4,200,000	3,000,000	2,400,000	2,400,000
Weighted average fixed price ($/MMBtu)	$ 3.05	$ 3.04	$ 3.06	$ 3.06	$ 3.20	$ 3.06	$ 3.07	$ 3.07
NYMEX HH[2] Natural Gas Purchased Puts:								
Notional volume (MMBtu)	—	—	—	—	600,000	600,000	600,000	600,000
Weighted average fixed price ($/MMBtu)	$ —	$ —	$ —	$ —	$ 3.00	$ 3.00	$ 3.00	$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:								
Notional volume (MMBtu)	—	—	—	—	600,000	600,000	600,000	600,000
Weighted average fixed price ($/MMBtu)	$ —	$ —	$ —	$ —	$ 3.15	$ 3.15	$ 3.15	$ 3.15
CIG[3] Basis Gas Swaps:								
Notional volume (MMBtu)	990,000	—	—	—	—	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.19)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

1. NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange.
2. NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange.
3. CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

As of December 31, 2016, the fair market value of our oil derivative contracts was a net liability of $47.2 million. Based on our open oil derivative positions at December 31, 2016, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $54.0 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $46.8 million. As of December 31, 2016, the fair market value of our natural gas derivative contracts was a net liability of $15.5 million. Based upon our open commodity derivative positions at December 31, 2016, a 10% increase in the NYMEX Henry Hub price would increase our net natural gas derivative liability by approximately $13.1 million, while a 10% decrease in the NYMEX Henry Hub price would decrease our net natural gas derivate liability by approximately $13.1 million. Please see "—Derivative Arrangements."

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of which can be predicted with certainty. For the year ended December 31, 2016, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact its operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At December 31, 2016, we had commodity derivative contracts with six counterparties. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, we use master netting agreements to minimize credit-risk exposure. The creditworthiness of our counterparties is subject to periodic review. Three of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at A3 classifications or above by Moody's. The other three counterparties had a corporate rating of Baa1 by Moody's. For the year ended December 31, 2016 and 2015, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contains credit-risk related contingent features.

Interest Rate Risk

At December 31, 2016, we had no variable-rate debt outstanding. Assuming we had the full amount of variable-rate debt outstanding available to us at December 31, 2016 of $474.4 million, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.7 million. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. See "—Liquidity and Capital Resources—Debt Arrangements."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXTRACTION OIL & GAS, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Extraction Oil & Gas, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in members' and stockholders' equity and cash flows present fairly, in all material respects, the financial position of Extraction Oil & Gas, Inc. and its subsidiaries as of December 31, 2016 and December 31, 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Denver, Colorado
March 13, 2017

EXTRACTION OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except unit and share data)

	December 31, 2016	December 31, 2015
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 588,736	$ 97,106
Accounts receivable		
Trade	23,154	27,927
Oil, natural gas and NGL sales	34,066	15,938
Inventory and prepaid expenses	7,722	7,938
Commodity derivative asset	—	68,885
Total Current Assets	653,678	217,794
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,851,052	1,128,022
Unproved oil and gas properties	452,577	374,194
Wells in progress	98,747	59,416
Less: accumulated depletion, depreciation and amortization	(402,912)	(181,382)
Net oil and gas properties	1,999,464	1,380,250
Other property and equipment, net of accumulated depreciation (Note 2)	32,721	30,402
Net Property and Equipment	2,032,185	1,410,652
Non-Current Assets:		
Cash held in escrow	42,200	—
Deferred equity issuance costs	—	942
Commodity derivative asset	—	2,906
Goodwill and other intangible assets, net of accumulated amortization	54,489	—
Other non-current assets	2,224	1,846
Total Non-Current Assets	98,913	5,694
Total Assets	$ 2,784,776	$ 1,634,140
LIABILITIES AND MEMBERS' / STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 131,134	$ 111,127
Revenue payable	35,162	38,752
Production taxes payable	27,327	19,061
Commodity derivative liability	56,003	—
Accrued interest payable	19,621	450
Asset retirement obligations	5,300	952
Total Current Liabilities	274,547	170,342
Non-Current Liabilities:		
Credit facility	—	225,000
Second Lien Notes, net of unamortized debt discount and debt issuance costs (Note 5)	—	412,790
Senior Notes, net of unamortized debt issuance costs (Note 5)	538,141	—
Production taxes payable	35,838	25,275
Commodity derivative liability	6,738	—
Other non-current liabilities	3,466	3,086
Asset retirement obligations	50,808	43,415
Deferred tax liability	106,026	—
Total Non-Current Liabilities	741,017	709,566
Commitments and Contingencies—Note 13		
Total Liabilities	1,015,564	879,908
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 and 0 issued and outstanding, respectively	153,139	—
Members' and Stockholders' Equity:		
Preferred tranche C units; unlimited units authorized; 0 and 78,444,117 issued and outstanding, respectively	—	250,338
Tranche A units; unlimited units authorized; 0 and 231,101,210 issued and outstanding, respectively	—	501,128
Common Stock, $0.01 par value; 900,000,000 shares authorized; 171,834,605 and 0 issued and outstanding, respectively	1,718	—
Additional paid-in capital	2,067,590	—
Retained earnings (deficit)	(453,235)	2,766
Total Members' and Stockholders' Equity	1,616,073	754,232
Total Liabilities and Members' / Stockholders' Equity	$ 2,784,776	$ 1,634,140

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART
OF THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	For the Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil sales	$ 194,059	$ 157,024	$ 75,460
Natural gas sales	48,652	26,019	9,247
NGL sales	35,378	14,707	8,133
Total Revenues	278,089	197,750	92,840
Operating Expenses:			
Lease operating expenses	62,043	30,628	5,067
Production taxes	20,730	17,035	9,743
Exploration expenses	36,422	18,636	126
Depletion, depreciation, amortization and accretion	205,348	146,547	34,042
Impairment of long lived assets	23,425	15,778	—
Other operating expenses	10,891	2,353	—
Acquisition transaction expenses	2,719	6,000	—
General and administrative expenses	232,388	37,149	19,598
Total Operating Expenses	593,966	274,126	68,576
Operating Income (Loss)	(315,877)	(76,376)	24,264
Other Income (Expense):			
Commodity derivatives gain (loss)	(100,947)	79,932	48,008
Interest expense	(68,843)	(51,030)	(22,454)
Other income	386	210	24
Total Other Income (Expense)	(169,404)	29,112	25,578
Net Income (Loss) Before Income Taxes	(485,281)	(47,264)	49,842
Income Tax Benefit	29,280	—	—
Net Income (Loss)	$ (456,001)	$ (47,264)	$ 49,842
Loss Per Common Share (Note 12)			
Basic and diluted	$ (1.54)		
Weighted Average Common Shares Outstanding			
Basic and diluted	149,029		

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' AND STOCKHOLDERS' EQUITY
(In thousands)

	Members' Units			Preferred Units		Preferred Stock		Common Stock				
	Tranche A Units	Preferred Tranche C Units	Amount	Units	Amount	Shares	Amount	Shares	Amount	Additional Paid in Capital	Retained Earnings (Deficit)	Total Equity
Balance at January 1, 2014	—	—	$ 1,174	—	$ —	—	$ —	—	$ —	$ —	$ 188	$ 1,362
Related party-note payable converted to equity	62,423	—	62,423	—	—	—	—	—	—	—	—	62,423
Convertible notes converted to equity	14,514	—	38,950	—	—	—	—	—	—	—	—	38,950
Units issued	150,175	—	403,038	—	—	—	—	—	—	—	—	403,038
Unit issuance costs	—	—	(9,843)	—	—	—	—	—	—	—	—	(9,843)
Promissory notes issued to officers	—	—	(5,368)	—	—	—	—	—	—	—	—	(5,368)
Restricted stock units issued	671	—	—	—	—	—	—	—	—	—	—	—
Unit-based compensation	—	—	4,462	—	—	—	—	—	—	—	—	4,462
Units issued for oil and gas properties	120	—	322	—	—	—	—	—	—	—	—	322
Net income	—	—	—	—	—	—	—	—	—	—	49,842	49,842
Balance at December 31, 2014	227,903	—	$ 495,158	—	$ —	—	$ —	—	$ —	$ —	$ 50,030	$ 545,188
Units issued	—	78,444	254,986	—	—	—	—	—	—	—	—	254,986
Unit issuance costs	—	—	(4,648)	—	—	—	—	—	—	—	—	(4,648)
Restricted units issued	3,198	—	—	—	—	—	—	—	—	—	—	—
Unit-based compensation	—	—	5,970	—	—	—	—	—	—	—	—	5,970
Net loss	—	—	—	—	—	—	—	—	—	—	(47,264)	(47,264)
Balance at December 31, 2015	231,101	78,444	$ 751,466	—	$ —	—	$ —	—	$ —	$ —	$ 2,766	$ 754,232
Units issued	—	37,345	121,370	—	—	—	—	—	—	—	—	121,370
Units repurchased	(1,327)	(82)	(8,429)	—	—	—	—	—	—	—	—	(8,429)
Settlement of promissory notes issued to officers	—	—	5,562	—	—	—	—	—	—	—	—	5,562
Unit issuance costs	—	—	(1,022)	—	—	—	—	—	—	—	—	(1,022)
Restricted units issued	7,661	—	—	—	—	—	—	—	—	—	—	—
Unit-based compensation	—	—	14,922	—	—	—	—	—	—	—	—	14,922
Stock-based compensation	—	—	—	—	—	—	—	—	—	185,386	—	185,386
Corporate Reorganization of Extraction Oil & Gas Holdings and Extraction Oil & Gas, Inc.	(237,435)	(115,707)	(883,869)	—	—	—	—	108,461	1,085	882,784	—	—
Net deferred tax liability due to Corporate Reorganization	—	—	—	—	—	—	—	—	—	(135,306)	—	(135,306)
Issuance of common stock in initial public offering	—	—	—	—	—	—	—	38,333	383	727,950	—	728,333
Issuance of common stock in private placement	—	—	—	—	—	—	—	25,041	250	456,749	—	456,999
Common stock issuance costs	—	—	—	—	—	—	—	—	—	(62,437)	—	(62,437)
Series A Preferred Units	—	—	—	75	75,000	—	—	—	—	—	—	—
Dividends paid on Series A Preferred Units	—	—	—	—	15,000	—	—	—	—	(15,000)	—	(15,000)
Series A Preferred Units issuance costs	—	—	—	—	(1,312)	—	—	—	—	(1,233)	—	(1,233)
Series A Preferred Unit redemption	—	—	—	(75)	(88,688)	—	—	—	—	—	—	—
Series B Preferred Units issued	—	—	—	185	185,280	—	—	—	—	—	—	—
Conversion of Series B Preferred Units to Series A Preferred Stock	—	—	—	(185)	(185,280)	185	185,280	—	—	—	—	—
Issuance costs on Series A Preferred Stock	—	—	—	—	—	—	(486)	—	—	—	—	—
Series B Preferred Unit and Series A Preferred Stock dividends	—	—	—	—	—	—	—	—	—	(2,958)	—	(2,958)
Beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	(32,696)	—	—	32,696	—	32,696
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	1,041	—	—	(1,041)	—	(1,041)
Net loss	—	—	—	—	—	—	—	—	—	—	(456,001)	(456,001)
Balance at December 31, 2016	—	—	$ —	—	$ —	185	$ 153,139	171,835	$ 1,718	$ 2,067,590	$ (453,235)	$ 1,616,073

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income (loss)	$ (456,001)	$ (47,264)	$ 49,842
Reconciliation of net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	205,348	146,547	34,042
Abandonment and impairment of unproved properties	22,318	16,414	—
Impairment of long lived assets	23,425	15,778	—
Non-cash acquisition transaction expenses	—	6,000	—
Amortization of debt issuance costs and debt discount	19,088	5,604	1,985
Deferred rent	551	488	—
Commodity derivatives (gain) loss	100,947	(79,932)	(48,008)
Settlements on commodity derivatives	42,827	55,770	1,724
Premiums paid on commodity derivatives	(611)	(5,744)	(1,867)
Deferred income tax benefit	(29,280)	—	—
Unit and stock-based compensation	200,308	5,970	4,462
Changes in current assets and liabilities:			
Accounts receivable—trade	(574)	7,723	(25,290)
Accounts receivable—oil, natural gas and NGL sales	(18,128)	(4,520)	(10,328)
Inventory and prepaid expenses	(1,110)	(1,024)	2,583
Accounts payable and accrued liabilities	(19,187)	24,452	11,096
Revenue payable	(6,602)	2,984	35,050
Production taxes payable	14,585	19,085	23,511
Accrued interest payable	19,171	277	173
Asset retirement expenditures	(687)	(1,742)	(662)
Due to related party	—	(183)	(923)
Net cash provided by operating activities	116,388	166,683	77,390
Cash flows from investing activities:			
Oil and gas property additions	(449,600)	(391,250)	(240,447)
Acquired oil and gas properties	(419,009)	(120,524)	(707,315)
Sale of oil and gas properties	2,656	4,742	—
Other property and equipment additions	(7,655)	(23,045)	(12,807)
Cash held in escrow	(42,200)	10,071	(10,071)
Net cash used in investing activities	(915,808)	(520,006)	(970,640)
Cash flows from financing activities:			
Related party - note payable converted to equity	—	—	38,750
Convertible notes converted to equity	—	—	38,950
Borrowings under credit facility	263,000	125,000	100,000
Repayments under credit facility	(488,000)	—	—
Proceeds from the issuance of Senior Notes	550,000	—	—
Proceeds from the issuance of Second Lien Notes	—	—	423,550
Repayments of Second Lien Notes	(430,000)	—	—
Proceeds from the issuance of units	121,370	254,986	397,670
Repurchase of units	(2,867)	—	—
Issuance of common stock	1,185,332	—	—
Issuance of Series A Preferred Units	75,000	—	—
Redemption of Series A Preferred Units	(88,688)	—	—
Proceeds from the issuance of Series B Preferred Units	185,280	—	—
Dividends on Series B Preferred Units	(721)	—	—
Debt issuance costs	(14,102)	(2,876)	(17,318)
Unit and common stock issuance costs	(64,554)	(5,706)	(9,512)
Net cash provided by financing activities	1,291,050	371,404	972,090
Increase in cash and cash equivalents	491,630	18,081	78,840
Cash and cash equivalents at beginning of period	97,106	79,025	185
Cash and cash equivalents at end of the period	$ 588,736	$ 97,106	$ 79,025
Supplemental cash flow information:			
Property and equipment included in accounts payable and accrued liabilities	$ 105,450	$ 72,236	$ 69,262
Acquisition transaction expenses paid through oil and gas properties	$ —	$ 6,000	$ —
Oil and gas property paid through units	$ —	$ —	$ 322
Cash paid for interest	$ 31,280	$ 50,380	$ 22,432
Cash paid for Second Lien Notes prepayment penalty	$ 4,300	$ —	$ —
Write-off of deposit on acquisition	$ 10,000	$ —	$ —
Accretion of beneficial conversion feature	$ 1,041	$ —	$ —
Promissory notes issued to officers	$ —	$ —	$ 5,368
Noncash settlement of promissory notes issued to officers	$ 5,562	$ —	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the “Company” or “Extraction”) is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado. The Company has nine subsidiaries, focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, as well as the design and support of midstream assets to gather and process crude oil and gas production focused in the DJ Basin of Colorado.

Extraction formerly known as Extraction Oil & Gas, LLC was converted from a Delaware limited liability company to a Delaware corporation, on October 12, 2016. In connection wih the initial public offering (the “IPO” or the “Offering”) on October 17, 2016, Extraction Oil & Gas Holdings, LLC (“Holdings”) was merged with and into Extraction, and Extraction was the surviving entity to the merger (the “Corporate Reorganization”). All equity holders in Holdings, other than the holders of the Series B Preferred Units (which were converted in connection with the closing of the IPO into shares of Series A Preferred Stock), but including the holders of restricted units and incentive units, received approximately 108.5 million shares of our common stock, with the allocation of such shares among our existing equity holders determined, pursuant to the terms of the limited liability company agreement of Holdings, by reference to an implied valuation based on the 10-day volume weighted average price of Extraction’s common stock following the closing of the IPO. Extraction is a public company listed for trading on the NASDAQ Global Select Market (“NASDAQ”) under the symbol “XOG”. The merger was treated as a reorganization of entities under common control. As part of Holdings' merger with and into Extraction, all of Holdings' other subsidiaries, including Extraction Oil & Gas, LLC became direct or indirect subsidiaries of Extraction. Please refer to *Note 9 — Members’ and Stockholders’ Equity* for further information on the Corporate Reorganization and IPO.

On December 12, 2016, the Company entered into the Private Placement Subscription Agreement (“Private Placement”), pursuant to which the Company agreed to issue approximately 25.0 million shares of common stock, at a price of $18.25 per share. Please refer to *Note 9 — Members’ and Stockholders’ Equity* for further information on the Private Placement.

The historical consolidated financial statements are based on the financial statements of our accounting predecessor, Holdings, prior to the Corporate Reorganization.

Extraction Oil & Gas Holdings, LLC, a Delaware limited liability company was formed on May 29, 2014 by PRE Resources, LLC (“PRL”) as a holding company with no independent operations apart from its ownership of the subsidiaries described below. PRL was formed in May 2012 to invest in oil and gas properties in Michigan, California, Wyoming, North Dakota and Colorado.

Extraction Oil & Gas, LLC (“Extraction LLC”) (“Extraction”), formerly a wholly-owned subsidiary of PRL, was a wholly-owned subsidiary of Holdings. Extraction LLC was formed on November 14, 2012, as a Delaware limited liability company and was focused on the acquisition, development and production of oil, natural gas and NGL natural gas liquids (“NGL”) reserves in the Rocky Mountains, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”)DJ Basin of Colorado.

Concurrent with the formation of Holdings, PRL contributed all of its membership interests in Extraction LLC, to Holdings and distributed all of its interests in Holdings to its members in a pro rata distribution (the “Reorganization”). As all power and authority to control the core functions of Holdings and Extraction LLC were controlled by PRL, the Reorganization was accounted for as a reorganization of entities under common control and the assets and liabilities of Extraction LLC were recorded at Extraction LLC’s historical costs. Results of operations for the 2014 period include the results of operations from Extraction LLC, the previously separate entity, from January 1, 2014 to May 29, 2014, the date the transfer was completed.

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company, including its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States ("GAAP"). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the consolidated financial information, have been included.

The consolidated financial statements have been retrospectively recast for all periods prior to May 29, 2014 to reflect the Reorganization as if the transfer of net assets occurred at the beginning of the period. Results of operations for the 2014 period include the results of operations from Extraction, the previously separate entity, from January 1, 2014 to May 29, 2014, the date the transfer was completed.

Use of Estimates in the Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of unit and stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible into cash and have original maturities of three months or less when purchased.

Cash Held in Escrow

Cash held in escrow includes deposits for the purchase of certain oil and gas properties as required under the related purchase and sale agreements.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. The Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. On an on-going basis, management reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables as of or for the years ended December 31, 2016 and 2015.

Credit Risk and Other Concentrations

The Company's cash and cash equivalents are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company often has balances in excess of the federally insured limits.

The Company sells oil, natural gas and natural gas liquids to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside the Company's control, none of which can be predicted with certainty. For the years ended December 31, 2016, 2015 and 2014, the Company had the following major customers that exceeded 10% of total oil, natural gas and NGL revenues. The Company does not believe the loss of any single purchaser would materially impact its operating results because crude oil, natural gas and NGLs are fungible products with well-established markets and numerous purchasers.

	For the Year Ended December 31,		
	2016	2015	2014
Customer A	25 %	— %	— %
Customer B	23 %	30 %	— %
Customer C	19 %	17 %	16 %
Customer D	16 %	17 %	8 %
Customer E	1 %	24 %	54 %

At December 31, 2016, the Company had commodity derivative contracts with six counterparties. The Company does not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are credit worthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The credit worthiness of the Company's counterparties is subject to periodic review. Three of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at A3 classifications or above by Moody's. The other three counterparties had a corporate rating of Baa1 by Moody's. For the years ended December 31, 2016, 2015 and 2014, the Company did not incur any losses with respect to counterparty contracts. None of the Company's existing derivative instrument contracts contains credit-risk related contingent features.

Inventory and Prepaid Expenses

The Company records well equipment inventory at the lower of cost or net realizable value. Prepaid expenses are recorded at cost. Inventory and prepaid expenses are comprised of the following (in thousands):

	As of December 31,	
	2016	2015
Well equipment inventory	$ 5,135	$ 6,238
Prepaid expenses	2,587	1,700
	$ 7,722	$ 7,938

Additionally, the Company recognized approximately $0.4 million of impairment expense on well equipment inventory for the year ended December 31, 2016. There were no impairments on inventory recognized for the years ended December 31, 2015 and 2014.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. For the years ended December 31, 2016 and 2015, the Company excluded $98.7 million and $59.4 million of capitalized costs from depletion related to wells in progress, respectively. For the years ended December 31, 2016, 2015 and 2014, the Company recorded depletion expense on capitalized oil and gas properties of $197.4 million, $140.2 million and $33.5 million, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed at each period end. Due to the capital-intensive nature and the geological characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. As of December 31, 2015, the Company had approximately $17.3 million in suspended well costs recorded, all capitalized less than one year, related to four exploratory wells in the northern field. The suspended well costs were included in wells in progress at December 31, 2015. These exploratory well costs were pending further engineering evaluation and analysis to determine if economic quantities of oil and gas reserves had been discovered. At June 30, 2016, the Company completed its evaluation and moved $21.8 million of these suspended well costs to proved oil and gas properties based on the determination of proved reserves. As of December 31, 2016, the Company did not have any suspended well costs as the analysis on economic and operating viability of the project was complete.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

The Company capitalizes interest, if debt is outstanding, during drilling operations in its exploration and development activities. For the years ended December 31, 2016, 2015 and 2014, the Company capitalized interest of approximately $5.2 million, $5.3 million and $2.6 million, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulate depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

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

Impairment of Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. For each of our fields, the Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and 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 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, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization. For the year ended December 31, 2016, the Company recognized $22.5 million in impairment expense on proved oil and gas properties in the Company's northern field. For the year ended December 31, 2015, the Company recognized $9.5 million in impairment expense on proved oil and gas properties in the Company's northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in its northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015. In December 2015, the Company sold proved oil and gas properties for proceeds of $4.7 million. As result, these assets were fair valued on the date of the transaction in accordance with ASC 360*, Property, Plant and Equipment*. The net book value of these assets exceeded the fair value by $2.7 million, which the Company recognized as impairment expense. The Company recognized a total of $12.2 million in impairment expense attributable to proved oil and gas properties for the year ended December 31, 2015. No impairment expense was recognized attributable to proved oil and gas properties for the year ended December 31, 2014.

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, the Company recognized $22.3 million and $16.4 million in impairment expense for the years ended December 31, 2016 and 2015, respectively. No impairment expense was attributable to unproved properties for the year ended December 31, 2014.

Other Property and Equipment

Other property and equipment consists of (i) midstream assets such as rights of way, pipelines, equipment and engineering costs, (ii) compressors used in Extraction's oil and gas operations, (iii) land, compressor stations, central tank batteries, and disposal well facilities and (iv) other property and equipment including, office furniture and fixtures, leasehold improvements and computer hardware and software. Impairment expense for other property and equipment is reported in impairment of long lived assets in the consolidated statements of operations. The Company recognized $0.5 million and $3.6 million in impairment expense related to midstream facilities for the years ended December 31, 2016 and 2015, respectively, which increased accumulated depreciation recognized in other property and equipment, net of accumulated depreciation. The Company recognized these impairment expenses as the result of contraction in the local oil and gas industry's near term growth profile, therefore decreasing the need and support for a specifically proposed gas processing facility. No impairment expense was recognized for the year ended December 31, 2014. Approximately $12.4 million of midstream assets, net of impairment expense, have not been placed into service and therefore are not currently being depreciated. Other property and equipment is recorded at cost and depreciated using the straight-line method. The estimated useful lives of those assets depreciated under the straight-line basis are as follows:

Rental equipment	10 years
Office leasehold improvements	3-10 years
Other	3-5 years

Other property and equipment is comprised of the following (in thousands):

	As of December 31,	
	2016	2015
Rental equipment	$ 2,910	$ 2,910
Land	12,978	14,778
Midstream facilities	16,530	10,783
Office leasehold improvements	4,360	3,967
Other	4,786	4,073
Less: accumulated depreciation	(8,843)	(6,109)
	$ 32,721	$ 30,402

Deferred Lease Incentives

All incentives received from landlords for office leasehold improvements are recorded as deferred lease incentives and amortized over the term of the respective lease on a straight-line basis as a reduction of rental expense.

Debt Discount Costs

The $430.0 million in Second Lien Notes issued in May of 2014 were issued at a 1.5% original issue discount ("OID") and the debt discount of $6.5 million was been recorded as a reduction of the Second Lien Notes. The debt discount costs related to Second Lien Notes were amortized to interest expense using the effective interest method over the term of the debt.

Debt Issuance Costs

Debt issuance costs include origination, legal, engineering, and other fees incurred to issue the debt in connection with the Company's credit facility, Second Lien Notes and Senior Notes. Debt issuance costs related to the credit facility are amortized to interest expense on a straight-line basis over the respective borrowing term. Debt issuance costs related to the Second Lien Notes and Senior Notes are amortized to interest expense using the effective interest method over the term of the debt.

Deferred Equity Issuance Costs

In conjunction with the IPO, costs incurred related to the IPO were capitalized as deferred equity issuance costs until the common shares were issued or the potential offering would have been terminated. Upon issuance of common shares, these costs were offset against the proceeds received. Offering costs include direct and incremental costs related to the offering, such as legal fees and related costs associated with the executed IPO.

Commodity Derivative Instruments

The Company has entered into commodity derivative instruments to reduce the effect of price changes on a portion of the Company's future oil and natural gas production. The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets and commodity derivative liabilities. The Company has not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, the Company does not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivative gain (loss) line on the consolidated statements of operations. The Company's cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in the Company's consolidated statements of cash flows.

Any premiums paid on derivative contracts are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid. Premium payments are reflected in cash flows from operating activities in our consolidated statements of cash flows. Over time, as the derivative contracts settle, the differences between the cash received and the premiums paid or fair value of contracts acquired are recognized in net gains or losses on commodity or interest rate derivate contracts, and the cash received is reflected in cash flows from operating activities in our consolidated statements of cash flows.

The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of these factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please refer to *Note 6 — Commodity Derivative Instruments* for additional discussion on commodity derivative instruments.

Goodwill and Other Intangible Assets

The Company accounts for goodwill and other intangible assets under the provisions of the ASC 350, *Intangibles-Goodwill and Other.* The Company's goodwill represents the excess of the purchase price over the fair value of net identifiable assets acquired in a business combination. Goodwill is not amortized and is tested for impairment annually on September 30 or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. When evaluating goodwill for impairment, the Company may first perform an assessment of qualitative factors to determine if the fair value of the reporting unit is more-likely-than-not greater than its carrying amount. If, based on the review of the qualitative factors, the Company determines it is not more-likely-than-not that the fair value of a reporting unit is less than its carrying value, the required two-step can be bypassed. If the Company does not perform a qualitative assessment or if the fair value of the reporting unit is not more-likely-than-not greater than its carrying value, the Company must perform the first step of the two-step impairment test and calculate the estimated fair value of the reporting unit. If the carrying value of the reporting unit exceeds the estimated fair value, there is an indication that impairment may exist, and the second step must be performed to measure the amount of impairment loss.

The amount of impairment for goodwill is measured as the amount by which the carrying amount of the goodwill exceeds the implied fair value of the goodwill. The Company performed a qualitative assessment as of December 31, 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license, which is typically one year or less. The Company acquired \$0.3 million of internal-use software licenses during the year ended December 31, 2016. Accumulated amortization for the year ended December 31, 2016 was \$0.1 million. There was no accumulated amortization for the years ended December 31, 2015 and 2014.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximates fair value as it bears interest at variable rates over the term of the loan. The Company's Second Lien Notes and Senior Notes are recorded at cost and the fair value is disclosed in *Note 8 — Fair Value Measurements*. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Asset Retirement Obligation

The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the Company makes the decision to complete the well or a well is acquired. For additional discussion on asset retirement obligations please refer to *Note 7 — Asset Retirement Obligations.*

Environmental Liabilities

The Company is subject to federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted values unless the timing of cash payments for the liability or component is fixed or determinable. Management has determined that no environmental liabilities existed as of December 31, 2016.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGLs are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company recognizes revenues from the sale of oil, natural gas and NGLs using the sales method of accounting, whereby revenue is recorded based on the Company's share of volume sold, regardless of whether the Company has taken its proportional share of volume produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. There were no material imbalances at December 31, 2016 and December 31, 2015.

Unit and Stock-Based Payments

The Company and its predecessor, Holdings, has granted restricted unit awards ("RUAs") to certain employees and nonemployee consultants of the Company, restricted stock awards ("RSUs") and stock option awards to certain employees of the Company, which therefore required the Company to recognize the expense in its financial statements.

All unit and stock-based payments to employees are measured at fair value on the grant date and expensed over the relevant service period. Unit-based payments to nonemployees are measured at fair value at each financial reporting date and expensed over the period of performance, such that aggregate expense recognized is equal to the fair value of the restricted units on the date performance is completed. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. All unit and stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations. Please refer to *Note 11 — Unit and Stock-Based Compensation* for additional discussion on unit and stock-based payments.

Income Taxes

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

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

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company does not currently have uncertain tax positions.

Holdings, the Company's accounting predecessor, was a limited liability company that was not subject to U.S. federal income tax. The Company became subject to U.S. Federal income tax on October 12, 2016, at the Corporate Reorganization.

Earnings Per Share

The Company's EPS calculation includes only the net income (loss) for the period subsequent to IPO and Corporate Reorganization which occurred on October 12, 2016 and has omitted EPS prior to this date. The Company uses the "if-converted" method to determine the potential dilutive effects of its Series A Preferred Stock, and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock units and stock option awards. 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 October 12, 2016, to December 31, 2016.

Segment Reporting

The Company operates in only one industry segment, which is the exploration and production of oil, natural gas and NGLs and related midstream activities. The Company's wholly-owned midstream subsidiaries are currently in the design phase and no revenue generating activities have commenced. All of the Company's operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Recent Accounting Pronouncements

The accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews new pronouncements to determine their impact, if any, on its financial statements.

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair of a reporting unit's goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in the financial statements that have been issued. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In December 2016, the FASB issued ASU No. 2016-19, which among other technical corrections and improvements, adds a reference to guidance to use when accounting for internal-use software licensed from third parties that is within the scope of Subtopic 350-40. For public entities, the guidance is effective upon issuance of the ASU. Adoption is permitted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The Company elected to adopt this guidance prospectively during the fourth quarter of 2016, which resulted in the capitalization of internal-use software licensed from third parties to goodwill and other intangible assets on the consolidated balance sheets. Costs are amortized over their respective service periods and expensed to depletion, depreciation, and amortization on the consolidated statements of operations.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In August 2016, the FASB issued ASU No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. In addition, in November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including an adoption in an interim period, with a required retrospective application to each period presented. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-09, which simplifies the accounting for share-based payment award transactions, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the consolidated statements of cash flows. ASU 2016-09 is effective for public companies for annual reporting periods beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted in any interim period or annual period with any adjustment reflected as of the beginning of the fiscal year of adoption. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, which clarifies the requirements to assess whether an embedded put or call option is clearly and closely related to the debt host, solely in accordance with the four-step decision sequence in FASB ASC Topic 815, *Derivatives and Hedging*, as amended by ASU 2016-06. This standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and should be applied using a modified retrospective approach. Early adoption is permitted. The Company is currently evaluating the impact of adopting ASU 2016-06, however the standard is not expected to have a significant effect on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right-of-use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. The Company is currently evaluating the impact this new standard will have on its financial statements. As part of our assessment work to-date, the Company formed an implementation work team, completed training of the new ASU's leasing guidance, and are developing a strategy for implementation.

In November 2015, the FASB issued ASU No. 2015-17. This ASU simplifies the presentation of deferred income taxes and requires deferred tax assets and liabilities be classified as noncurrent in the balance sheet. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. Entities can transition to the standard either retrospectively to each period presented or prospectively. The Company has elected to early adopt this guidance during the fourth quarter of 2016, under the prospective method. The adoption of this standard did not have a significant impact on the Company’s financial statements as our accounting predecessor, Holdings, was not subject to U.S. federal income tax.

In September 2015, the FASB issued ASU No. 2015-16. This ASU eliminates the requirement to retrospectively apply measurement-period adjustments made to provisional amounts recognized in a business combination. The accounting update also requires an entity to present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings, by line item, that would have been recorded in previous reporting periods if the adjustment to the estimated amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. This standard should be applied prospectively, and early adoption is permitted. The Company elected for early adoption for its year end December 31, 2015 financial statements. The adoption of this standard did not have a significant impact on the Company’s financial statements.

In July 2015, the FASB issued ASU No. 2015-11, which updates the authoritative guidance for inventory, specifically that inventory should be valued at each reporting period at the lower of cost or net realizable value. This guidance is effective for the annual period beginning after December 15, 2016; early adoption is permitted. The Company elected for early adoption during the fourth quarter of 2016. The adoption of this standard did not have a significant impact on the Company’s financial statements.

In April 2015, the FASB issued ASU No. 2015-03, with an objective to simplify the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Effective January 1, 2016, the Company adopted ASU No. 2015-03 on a retrospective basis. FASB ASU No. 2015-03 should be applied retrospectively and represent a change in accounting principle.

In August 2015, the FASB issued ASU No. 2015-15, which amends ASU 2015-03 which had not addressed the balance sheet presentation of debt issuance costs incurred in connection with line-of-credit arrangements. Under ASU 2015-15, a Company may defer debt issuance costs associated with line-of-credit arrangements and present such costs as an asset, subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. ASU 2015-15 is consistent with how the Company currently accounts for debt issuance costs related to the Company’s credit facility.

In November 2014, the FASB issued ASU No. 2014-16, which updates authoritative guidance for derivatives and hedging instruments, specifically in determining whether the host contract in a hybrid financial instrument issued in the form of a share is more akin to debt or to equity. This guidance is effective for the annual period beginning after December 15, 2015; early adoption is permitted. The Company is currently evaluating the impact of this new standard; however, the Company does not expect adoption to have a material impact on its financial statements.

In August 2014, the FASB issued ASU No. 2014-15, with an objective to provide guidance on management’s responsibility to evaluate whether there is substantial doubt about a company’s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for fiscal years ending after December 15, 2016, and annual and interim periods thereafter. This standard did not have an impact on the Company’s financial statements.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and is effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of reporting periods beginning after December 15, 2016. The FASB subsequent issued ASU 2016-08, ASU 2016-10, ASU 2016-11 and ASU 2016-12, and 2016-20, which provided additional implementation guidance. The Company is currently evaluating the level of effort necessary to implement the standards, evaluating the provisions of each of these standards, and assessing their potential impact on the Company's financial statements and disclosures, as well as determining whether to use the full retrospective method or the modified retrospective method. The Company is currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on our financial position and results of operations. As part of our assessment work to-date, the Company formed an implementation work team, completed training of the new ASU's revenue recognition model, and are developing a strategy for implementation.

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2016, and through the date of this filing that would have a material impact on the Company's financial statements.

Note 3—Oil and Gas Properties

The Company's oil and gas properties are entirely within the United States. The net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	As of December 31,	
	2016	**2015**
Proved oil and gas properties	$ 1,851,052	$ 1,128,022
Unproved oil and gas properties(1)	452,577	374,194
Wells in progress(2)	98,747	59,416
Total capitalized costs(3)	$ 2,402,376	$ 1,561,632
Accumulated depletion, depreciation and amortization	(402,912)	(181,382)
Net capitalized costs	$ 1,999,464	$ 1,380,250

(1) Unproved oil and gas properties represent unevaluated costs the Company excludes from the amortization base until proved reserves are established or impairment is determined.
(2) Costs from wells in progress are excluded from the amortization base until production commences.
(3) Includes accumulated interest capitalized of $13.4 million, $8.2 million, and $2.9 million as of December 31, 2016 and 2015, respectively.

The following table presents information regarding the Company's net costs incurred in oil and gas property acquisition, exploration and development activities (in thousands):

	For the Year Ended December 31,	
	2016	**2015**
Property acquisition costs:		
Proved	$ 319,832	$ 80,952
Unproved	220,213	120,651
Exploration costs(1)	13,588	19,584
Development costs	317,228	337,968
Total	$ 870,861	$ 559,155
Total excluding asset retirement obligations	$ 863,874	$ 523,531

(1) Exploration costs do not include impairment and abandonment costs of unproved properties, which are included in the line item exploration expenses in the consolidated statements of operations. For the year ended December 31, 2014, there were no significant exploration expenses or abandonment and impairment of unproved properties.

Note 4—Acquisitions

November 2016 Acquisition

On November 22, 2016, the Company acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the Core DJ Basin for approximately $120.0 million, including customary closing adjustments. The Company also made a $41.1 million deposit in November 2016 in conjunction with November 2016 Acquisition, which has been reflected in the December 31, 2016 consolidated balance sheets within the cash held in escrow line item. The deposit was made for two additional closings of leaseholds located in the Core DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres. The second closing is expected to occur in the first half of 2017 and will add approximately 800 net acres.

October 2016 Acquisition

On October 3, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,400 net acres of leasehold, and related producing and non-producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "Bayswater Assets" and the acquisition, the "October 2016 Acquisition" or the "Bayswater Acquisition"). The seller received aggregate consideration of approximately $405.3 million in cash. The effective date for the acquisition was July 1, 2016, with purchase price adjustments calculated as of the closing date on October 3, 2016. The acquisition provides new development opportunities in the DJ Basin as well as increases the Company's existing working interest, as the majority of the locations are located on acreage in which the Company already owns a majority working interest and operates. The acquired producing properties contributed revenue of $17.2 million for the year ended December 31, 2016. The Company determined that it is not practical to calculate net income associated with October 2016 Acquisition. The Company incurred $2.6 million of transaction costs related to the acquisition for year ended December 31, 2016. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expenses line item. No transaction costs related to the acquisition were incurred for the years ended December 31, 2015 and 2014.

The acquisition is accounted for using the acquisition method under *ASC 805, Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of October 3, 2016. In February 2017, the Company completed the transaction's first post-closing settlement. The Company notes the purchase price allocation is preliminary as certain working capital adjustments may occur in the future. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed (in thousands):

Preliminary Purchase Price	**October 3, 2016**
Consideration given	
Cash	$ 405,335
Total consideration given	$ 405,335
Preliminary Allocation of Purchase Price	
Proved oil and gas properties	$ 252,522
Unproved oil and gas properties	109,800
Total fair value of oil and gas properties acquired	$ 362,322
Goodwill [(1)]	$ 54,220
Working capital	(7,185)
Asset retirement obligations	(4,022)
Fair value of net assets acquired	$ 405,335
Working capital acquired was estimated as follows:	
Accounts receivable	$ 955
Revenue payable	(3,012)
Production taxes payable	(4,244)
Accrued liabilities	(884)
Total working capital	$ (7,185)

(1) Goodwill is primarily attributable to a decrease in commodity prices from the time the acquisition was negotiated and commodity prices on October 3, 2016 and the operational and financial synergies expected to be realized from

the acquisition. Goodwill recognized as a result of the Bayswater Acquisition is not deductible for income tax purposes.

Option to Acquire Additional Assets from October 2016 Acquisition

Upon the closing of the October 2016 Acquisition, the Company made a $10.0 million non-refundable payment for an option to purchase additional assets from the seller of the October 2016 Acquisition (the "Additional Assets") for an additional $190.0 million, for a total purchase price for the Additional Assets of $200.0 million. The option may be exercised at any time until March 31, 2017. If the Company does not exercise the option to acquire the Additional Assets, the seller will have the right until April 30, 2017 to elect to sell those assets to the Company for an additional $120.0 million, for a total purchase price for the Additional Assets of $130.0 million. In March 2017, the Company entered into an amendment to this agreement with Bayswater to terminate both our and Bayswater's options for no further consideration. The $10.0 million was expensed in the fourth quarter of 2016 to other operating expenses within our consolidated statements of operations.

August 2016 Acquisition

On August 23, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 1,100 net acres of leasehold located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way and other assets (the "August 2016 Acquisition"). The seller received aggregate consideration of approximately $13.7 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date on August 23, 2016. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area. The acquired producing properties contributed de minimis revenue or earnings for the year ended December 31, 2016. The Company incurred $0.1 million of transaction costs related to the acquisition for the year ended December 31, 2016. No transaction costs related to the acquisition were incurred for the years ended December 31, 2015 and 2014. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expenses line item.

The acquisition is accounted for using the acquisition method under *ASC 805, Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of August 23, 2016. The Company has not completed the transaction's post-closing settlement, which is scheduled to occur in late March 2017. As the post-close has not occurred, management has not had the opportunity to complete its assessment of the fair values of assets acquired and liabilities assumed. Accordingly, the below allocation will change as additional information becomes available and is assessed by the Company, and the impact of such changes may be material. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed (in thousands):

Preliminary Purchase Price	**August 23, 2016**
Consideration given	
Cash	$ 13,674
Total consideration given	$ 13,674
Preliminary Allocation of Purchase Price	
Proved oil and gas properties	$ 9,824
Unproved oil and gas properties	6,872
Total fair value of oil and gas properties acquired	$ 16,696
Working capital	$ —
Asset retirement obligations	(3,022)
Fair value of net assets acquired	$ 13,674
Working capital acquired was estimated as follows (1):	
Accounts receivable	$ —
Revenue payable	—
Production taxes payable	—
Total working capital	$ —

(1) The Company anticipates acquiring various working capital items such as accounts receivable, revenue payable and production taxes payable liabilities. These working capital adjustments will result in an adjustment to the consideration at closing. At this time, the working capital adjustments could not be estimated.

March 2015 Acquisition

On March 10, 2015, the Company acquired an unaffiliated oil and gas company's interests in approximately 39,000 net acres of leasehold, and related producing properties located primarily in Adams, Broomfield, Boulder and Weld Counties, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "March 2015 Acquisition"). The seller received aggregate consideration of approximately $120.5 million in cash. The effective date for the acquisition was January 1, 2014, with purchase price adjustments calculated as of the closing date on March 10, 2015. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area and the acquired producing properties contributed revenue of $8.0 million to the Company for the year ended December 31, 2015. The Company determined that it is not practical to calculate net income associated with March 2015 Acquisition. The Company incurred $0.5 million of transaction costs related to the acquisition for the year ended December 31, 2015. These transaction costs are recorded in the consolidated statements of operations within the general and administrative expenses line item. No transaction costs related to the acquisition were incurred for the year ended December 31, 2016. Additionally, the Company incurred $6.0 million of non-cash transaction costs associated with a finder's fee to an unaffiliated third-party. The Company assigned an over-riding royalty interest in the proved and unproved oil and gas properties acquired in the March 2015 Acquisition, which had a fair value of $6.0 million on the measurement date. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of March 10, 2015. In November 2015, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**March 10, 2015**
Consideration given	
Cash	$ 120,524
Total consideration given	$ 120,524
Allocation of Purchase Price	
Proved oil and gas properties	$ 80,952
Unproved oil and gas properties	69,450
Total fair value of oil and gas properties acquired	$ 150,402
Working capital	$ (1,996)
Asset retirement obligations	(27,882)
Fair value of net assets acquired	$ 120,524
Working capital acquired was estimated as follows:	
Accounts receivable	$ 462
Revenue payable	(718)
Production taxes payable	(1,740)
Total working capital	$ (1,996)

October 2014 Acquisition

On October 15, 2014, the Company acquired an unaffiliated oil and gas company's interests in 29 producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts and equipment (the "October 2014 Acquisition"). The seller received aggregate consideration of approximately $1.3 million in cash. The effective date for the acquisition was July 1, 2014, with purchase price adjustments calculated as of the closing date on October 15, 2014. The acquisition expanded the Company's core project area. The Company incurred $0.4 million of transaction costs related to the acquisition for the year ended December 31, 2014. No transaction costs related to the acquisition were incurred for the years ended December 31, 2016 and 2015. Transaction costs are recorded in the consolidated statements of operations within the general and administrative expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of October 15, 2014. In January 2015, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**October 15, 2014**
Consideration given	
Cash	$ 1,343
Total consideration given	$ 1,343
Allocation of Purchase Price	
Proved oil and gas properties	$ 6,592
Total fair value of oil and gas properties acquired	$ 6,592
Working capital	$ (4,657)
Asset retirement obligations	(592)
Fair value of net assets acquired	$ 1,343
Working capital acquired was estimated as follows:	
Accounts receivable	$ 135
Revenue payable	(205)
Production taxes payable	(574)
Accrued liabilities	(4,013)
Total working capital	$ (4,657)

August 2014 Acquisition

On August 21, 2014, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,400 net acres of leaseholds, and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "August 2014 Acquisition"). The seller received aggregate consideration of approximately $297.1 million in cash. The effective date for the acquisition was March 1, 2014, with purchase price adjustments calculated as of the closing date on August 21, 2014. The acquisition provided strategic additions adjacent to the Company's core project area. The Company incurred $0.4 million of transaction costs related to the acquisition for the year ended December 31, 2014. No transaction costs related to the acquisition were incurred for the years ended December 31, 2016 and 2015. Transaction costs are recorded in the consolidated statements of operations within the general and administrative expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of August 21, 2014. In April 2015, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**August 21, 2014**
Consideration given	
Cash	$ 297,112
Total consideration given	$ 297,112
Allocation of Purchase Price	
Proved oil and gas properties	$ 167,826
Unproved oil and gas properties	132,568
Total fair value of oil and gas properties acquired	$ 300,394
Working capital	(1,787)
Asset retirement obligations	(1,495)
Fair value of net assets acquired	$ 297,112
Working capital acquired was estimated as follows:	
Accounts receivable	$ 9,065
Well equipment inventory	503
Revenue payable	(4,967)
Production taxes payable	(1,688)
Accrued liabilities	(4,700)
Total working capital	$ (1,787)

July 2014 Acquisition

On July 28, 2014, the Company acquired an unaffiliated oil and gas company's interests in approximately 9,000 net acres of leaseholds, and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "July 2014 Acquisition"). The seller received aggregate consideration of approximately $113.4 million in cash. The effective date for the acquisition was March 1, 2014, with purchase price adjustments calculated as of the closing date on July 28, 2014. The acquisition provided strategic additions adjacent to the Company's core project area. The Company incurred $0.3 million of transaction costs related to the acquisition for the year ended December 31, 2014. No transaction costs related to the acquisition were incurred for the years ended December 31, 2016 and 2015. Transaction costs are recorded in the consolidated statements of operations within the general and administrative expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of July 28, 2014. In October 2014, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**July 28, 2014**
Consideration given	
Cash	$ 113,410
Total consideration given	$ 113,410
Allocation of Purchase Price	
Proved oil and gas properties	$ 62,350
Unproved oil and gas properties	52,508
Total fair value of oil and gas properties acquired	$ 114,858
Working capital	2,337
Asset retirement obligations	(3,785)
Fair value of net assets acquired	$ 113,410
Working capital acquired was estimated as follows:	
Accounts receivable	$ 5,157
Revenue payable	(297)
Production taxes payable	(1,160)
Accrued liabilities	(1,363)
Total working capital	$ 2,337

May 2014 Acquisition

On May 29, 2014, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,200 net acres of leaseholds, and related producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment and other assets (the "May 2014 Acquisition"). The seller received aggregate consideration of approximately $219.3 million in cash. The effective date for the acquisition was January 1, 2014, with purchase price adjustments calculated as of the closing date on May 29, 2014. This acquisition was the Company's initial entrance into the DJ Basin of significant size, the Company's core project area. The Company incurred $0.4 million of transaction costs related to the acquisition for the year ended December 31, 2014. No transaction costs related to the acquisition were incurred for the years ended December 31, 2016 and 2015. Transaction costs are recorded in the consolidated statements of operations within the general and administrative expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of May 29, 2014. In December 2014, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**May 29, 2014**
Consideration given	
Cash	$ 219,320
Total consideration given	$ 219,320
Allocation of Purchase Price	
Proved oil and gas properties	$ 140,275
Unproved oil and gas properties	73,600
Total fair value of oil and gas properties acquired	$ 213,875
Working capital	5,675
Asset retirement obligations	(230)
Fair value of net assets acquired	$ 219,320
Working capital acquired was estimated as follows:	
Accounts receivable	$ 19,081
Revenue payable	(5,994)
Production taxes payable	(4,328)
Accrued liabilities	(3,084)
Total working capital	$ 5,675

Pro Forma Financial Information (Unaudited)

For the years ended December 31, 2016 and 2015, the following pro forma financial information represents the combined results for the Company and the properties acquired in October 2016 as if the acquisition and related financing had occurred on January 1, 2015 and for the properties acquired in March 2015 as if the acquisition and related financing had occurred on January 1, 2014. For the year ended December 31, 2014, the following pro forma financial information represents the combined results for the Company and the properties acquired in March 2015 as if the acquisition and related financing had occurred on January 1, 2014, and for the properties acquired in October 2014, August 2014, July 2014 and May 2014 as if these acquisitions and related financing had occurred on January 1, 2014 (all in thousands, except per share data). For purposes of the pro forma financial information, it was assumed that the October 2016 Acquisition was funded through the issuance of $260.3 million in convertible preferred securities and borrowings under the revolving credit facility. For purposes of the pro forma financial information, it was assumed that the Company issued equity to finance the March 2015 Acquisition. For purposes of the pro forma it was assumed that the 2014 acquisitions were funded through capital contributions of $419.0 million and proceeds from the Second Lien Notes of $288.5 million. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $23.1 million, $1.5 million and $17.2 million for the years ended December 31, 2016, 2015 and 2014, respectively. The pro forma information includes the effects of a decrease in non-recurring transaction costs that are included in general and administrative expenses and acquisition transaction expenses of $2.6 million, $6.4 million and $1.8 million for the years ended December 31, 2016, 2015 and 2014, respectively. No pro forma adjustments were made for amortization of debt issuance and debt discount costs for the years ended December 31, 2016 and 2015. The pro forma information includes the effects of adjustments for the amortization of debt issuance and debt discount costs of $1.3 million for the year ended December 31, 2014. The pro forma information includes the effects of adjustments for the incremental interest expense on acquisition financing of $4.0 million, $4.0 million, and $15.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. No pro forma adjustments were made for the effect of income taxes for the years ended December 31, 2016, 2015 and 2014 as the acquisitions occurred before the Corporate Reorganization. Additionally, the pro forma financial information excludes the effects the August 2016 Acquisition as these pro forma adjustments were de minimis.

The following pro forma results (in thousands, except per share data) do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results. Net income (loss) per share is not applicable for the period prior to the Corporate Reorganization.

	For the Year Ended December 31,		
	2016	**2015**	**2014**
Revenues	$ 325,355	$ 214,259	$ 170,970
Net income (loss)	$ (441,571)	$ (33,524)	$ 75,288
Income (loss) per share			
Basic and diluted	$ (1.54)		

Note 5—Long-Term Debt

As of the dates indicated the Company's long-term debt consisted of the following (in thousands):

	As of December 31,	
	2016	**2015**
Credit facility due November 29, 2018	$ —	$ 225,000
Second Lien Notes due May 29, 2019	—	430,000
Senior Notes due July 15, 2021	550,000	—
Unamortized debt discount and debt issuance costs on Second Lien Notes and Senior Notes	(11,859)	(17,210)
Total long-term debt	538,141	637,790
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 538,141	$ 637,790

Credit Facility

On September 4, 2014, Holdings entered into a credit facility with a syndicate of banks, which is subject to a borrowing base. In connection with the IPO and the merger of Holdings into the Company, the Company assumed all of the obligations of Holdings under the credit facility and became the borrower thereunder. The credit facility matures on November 29, 2018. As of December 31, 2016, the credit facility was subject to a borrowing base of $475.0 million and total commitments of $1.0 billion. As of December 31, 2016, the Company did not have any outstanding borrowings and as of December 31, 2015, the Company had outstanding borrowings of $225.0 million. As of December 31, 2016 and December 31, 2015, the Company had standby letters of credit of $0.6 million and $0.7 million, respectively. At December 31, 2016, the available credit under the credit facility was $474.4 million. As of the date of this filing, the Company has no balance outstanding under the credit facility.

Redetermination of the borrowing base occurred initially quarterly (on February 1, 2015, May 1, 2015, August 1, 2015, November 1, 2015 and February 1, 2016) and semiannually thereafter on May 1 and November 1. Additionally, the Company and the administrative agent under the credit facility may each elect a redetermination of the borrowing base between any two scheduled redeterminations, and the Company may elect a redetermination of the borrowing base on August 1, 2017.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the Pricing Grid. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	LIBOR Margin	Base Rate Margin	Commitment Fee
Level 1	< 25 %	2.00 %	1.00 %	0.375 %
Level 2	≥ 25% < 50%	2.25 %	1.25 %	0.375 %
Level 3	≥ 50% < 75%	2.50 %	1.50 %	0.500 %
Level 4	≥ 75% < 90%	2.75 %	1.75 %	0.500 %
Level 5	≥ 90 %	3.00 %	2.00 %	0.500 %

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants; and (v) holding cash balances in excess of certain thresholds while carrying a balance on the credit facility. Additionally, the credit facility limits the Company from hedging in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply with a current ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, the second lien notes and certain derivative assets), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of consolidated debt less cash balances in excess of certain thresholds to our consolidated EBITDAX (EBITDAX is defined as net income adjusted for certain cash and non-cash items including depreciation, depletion, amortization and accretion, exploration expense, gains/losses on derivative instruments, amortization of certain debt issuance costs, non-cash compensation expense, interest expense and prepayment premiums on extinguishment of debt) for the four fiscal quarter period most recently ended, of not greater than 4.0:1.0. For the quarters ending between and including December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3. For the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX. The Company was in compliance with all financial covenants under the credit facility as of December 31, 2016.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and its subsidiaries, including oil and gas properties, personal property and the equity interests of the subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility.

Second Lien Notes

On May 29, 2014, Holdings entered in to a five year, $430.0 million term loan facility with a syndicate of lenders (the "Second Lien Notes"). The Second Lien Notes would have matured on May 29, 2019. Holdings had drawn the full $430.0 million under the Second Lien Notes and no further commitments remained. The loan was drawn in four tranches: $230.0 million in May 2014 that bore an interest rate of 11.0%, $75.0 million in July 2014 that bore an interest rate of 11.0%; $75.0 million in August 2014 that bore an interest rate of 10.0%, and $50.0 million in October 2014 that bore an interest rate of 10.0%. The interest rates were fixed and interest was payable semi-annually.

In July 2016, the Second Lien Notes were repaid and terminated in conjunction with the Senior Notes Offering. The Company used the proceeds from the Senior Notes (as discussed below) to repay the outstanding $430.0 million of principal and a $4.3 million prepayment penalty. The prepayment penalty was expensed during the year ended December 31, 2016 in the consolidated statements of operations within the interest expense line item. Additionally, during the year ended December 31, 2016, the Company wrote off approximately $15.1 million of unamortized debt discount and debt issuance costs that were related to the Second Lien Notes. The write off of the unamortized debt discount and debt issuance costs were recorded in the consolidated statements of operations within the interest expense line item.

Senior Notes

In July 2016, the Company issued at par $550.0 million principal amount of 7.875% Senior Notes due July 15, 2021 (the "Senior Notes" and the offering, the Senior Notes Offering). The Senior Notes bear an annual interest rate of 7.875%. The interest on the Senior Notes is payable on January 15 and July 15 of each year commencing on January 15, 2017. The Company received net proceeds of approximately $537.2 million after deducting discounts and fees. All of the net proceeds from the Senior Notes were used to repay all of the outstanding borrowings and related premium, fees and expenses on the Second Lien Notes (which were terminated concurrently with such repayment), and the remaining proceeds were used to repay borrowings under the credit facility and for general business purposes.

Our Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes) that guarantees our indebtedness under a credit facility. The notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the notes.

The Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company's or any of its Guarantors' equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Senior Notes may declare all outstanding Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under the Indenture as of December 31, 2016, and through the filing of this report.

Debt Discount Costs on Second Lien Notes

The Company's Second Lien Notes were issued with an original issue discount (OID) of $6.5 million. In July 2016, the Company repaid the Second Lien Notes in full and accelerated the remaining unamortized balance of $4.3 million. This expense was recorded in the consolidated statements of operations within the interest expense line item. As of December 31, 2016, there was no remaining balance on the OID.

Debt Issuance Costs

As of December 31, 2016 and 2015, the Company had debt issuance costs net of accumulated amortization of $2.2 million and $1.8 million, respectively, related to its credit facility which has been reflected on the Company's balance sheet within the line item other non-current assets. As of December 31, 2016, the Company had debt issuance costs of $11.9 million related to its Senior Notes which has been reflected on the Company's balance sheet within the line item Senior Notes, net of unamortized debt issuance costs. Upon the repayment of the Company's Second Lien Notes, the Company accelerated the amortization of the remaining $10.8 million of unamortized debt issuance costs. This expense was recorded in the consolidated statements of operations within the interest expense line item. As of December 31, 2016, there was no remaining balance on debt issuance costs associated with the Second Lien Notes. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility, Second Lien Notes and Senior Notes. For the years ended December 31, 2016, 2015, and 2014, the Company recorded amortization expense related to the debt issuance costs of $14.4 million, $3.1 million and $1.5 million, respectively.

Interest Incurred On Long-Term Debt

For the years ended December 31, 2016, 2015 and 2014, the Company incurred interest expense on long-term debt of $50.5 million, $50.5 million and $23.1 million, respectively and capitalized interest of $5.2 million, $5.3 milllion and $2.6 million, for the years ended December 31, 2016, 2015 and 2014, respectively, which has been reflected in the Company's financial statements. Also included in interest expense for the year ended December 31, 2016 is a prepayment penalty of $4.3 million related to the Company's repayment of its Second Lien Notes in July 2016.

Note 6—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options, and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with six counterparties. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

There are no credit-risk-related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of December 31, 2016 are summarized below:

	2017	2018
NYMEX WTI[1] Crude Swaps:		
Notional volume (Bbl)	1,500,000	900,000
Weighted average fixed price ($/Bbl)	$ 43.84	$ 55.94
NYMEX WTI[1] Crude Sold Calls:		
Notional volume (Bbl)	6,000,000	3,400,000
Weighted average sold call price ($/Bbl)	$ 55.91	$ 62.26
NYMEX WTI[1] Crude Sold Puts:		
Notional volume (Bbl)	6,100,000	3,000,000
Weighted average sold put price ($/Bbl)	$ 37.74	40.00
NYMEX WTI[1] Crude Purchased Puts:		
Notional volume (Bbl)	6,000,000	3,300,000
Weighted average purchased put price ($/Bbl)	$ 47.64	$ 50.00
NYMEX HH[2] Natural Gas Swaps:		
Notional volume (MMBtu)	25,420,000	12,000,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH[2] Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG[3] Basis Gas Swaps:		
Notional volume (MMBtu)	990,000	—
Weighted average fixed basis price ($/MMBtu)	$ (0.19)	

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

Commodity derivatives gain (loss) are included under other income (expense) in the consolidated statements of operations. The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the balance sheets (in thousands):

	As of December 31, 2016				
Location on Balance Sheet	Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet[1]	Net Amounts of Assets and Liabilities Presented in the Balance Sheet	Gross Amounts not Offset in the Balance Sheet[2]	Net Amounts[3]
Current assets	$ 12,620	$ (12,620)	$ —	$ —	$ —
Non-current assets	$ 14,993	$ (14,993)	$ —	$ —	$ —
Current liabilities	$ (68,623)	$ 12,620	$ (56,003)	$ —	$ (62,741)
Non-current liabilities	$ (21,731)	$ 14,993	$ (6,738)	$ —	$ —

Location on Balance Sheet	As of December 31, 2015 Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet(1)	Net Amounts of Assets and Liabilities Presented in the Balance Sheet	Gross Amounts not Offset in the Balance Sheet(2)	Net Amounts(3)
Current assets	$ 89,746	$ (20,861)	$ 68,885	$ —	$ 71,791
Non-current assets	$ 5,916	$ (3,010)	$ 2,906	$ —	$ —
Current liabilities	$ (20,861)	$ 20,861	$ —	$ —	$ —
Non-current liabilities	$ (3,010)	$ 3,010	$ —	$ —	$ —

(1) Agreements are in place with all of the Company's financial trading counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the balance sheet. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line item and all counterparties in a net liability position are shown in the current liability line item.

The table below sets forth the commodity derivatives gain (loss) for the years ended December 31, 2016, 2015 and 2014 (in thousands). Commodity derivatives gain (loss) are included under other income (expense).

	For the Year Ended December 31, 2016	2015	2014
Commodity derivatives gain (loss)	$ (100,947)	$ 79,932	$ 48,008

Note 7—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable local, state and federal laws, and applicable lease terms. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit of production method.

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

	For the Year Ended December 31, 2016	2015
Balance beginning of period	$ 44,367	$ 6,450
Liabilities incurred or acquired	8,945	35,624
Liabilities settled	(1,155)	(1,742)
Revisions in estimated cash flows	(1,695)	—
Accretion expense	5,646	4,035
Balance end of period	$ 56,108	$ 44,367

Note 8—Fair Value Measurements

ASC 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2016 and December 31, 2015 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at December 31, 2016 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ —	$ —	$ —
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 62,741	$ —	$ 62,741

	Fair Value Measurements at December 31, 2015 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 71,791	$ —	$ 71,791
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ —	$ —	$ —

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options, and call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair value of the Second Lien Notes and Senior Notes was derived from available market data. As such, the Company has classified the Second Lien Notes and Senior Notes as Level 2. Please refer to *Note 5 — Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At December 31, 2016		At December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit facility	$ —	$ —	$ 225,000	$ 225,000
Second Lien Notes[(1)]	$ —	$ —	$ 412,790	$ 433,196
Senior Notes[(2)]	$ 538,141	$ 588,500	$ —	$ —

(1) The carrying amount of the Second Lien Notes includes unamortized debt discount and debt issuance costs of $17.2 million as of December 31, 2015.

(2) The carrying amount of the Senior Notes includes unamortized debt issuance costs of $11.9 million as of December 31, 2016.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property and goodwill. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts are circumstances arise that indicate a need for measurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash-flows of producing property. The future cash-flows are based on Management's estimates for the future. Unobservable inputs included estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms or forward price curves, operating and development costs, and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). For the year ended December 31, 2016, the Company recognized $22.5 million in impairment expense on proved oil and gas properties. For the year ended December 31, 2015, the Company recognized $9.5 million in impairment expense on proved oil and gas properties. The impairment expense for the years ended December 31, 2016 and 2015 is related to impairment of the assets in the Company's northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in the Company's northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015, respectively. Additionally, during 2015, the Company sold proved oil and gas properties for proceeds of $4.7 million. In connection with the sale, the Company determined that assets' net book value exceeded the fair value of such properties by $2.7 million. The Company recognized that amount as an impairment expense for the year ended December 31, 2015.

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30 or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents our oil and gas operations in the DJ Basin. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. The Company utilizes the market approach to determine the fair value of our reporting unit. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's shares could change our estimates of the fair value of our reporting unit and could result in an impairment charge. The Company performed a qualitative assessment as of December 31, 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

The Company's other non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations, please refer to *Note 4 — Acquisitions*. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted-cash flow approach using level 3 inputs. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices, development costs, and operating costs, based on market participant assumptions. The fair value of assets or liabilities associated with purchase price allocations is on a non-recurring basis and is not measured in periods after initial recognition.

Note 9—Members' and Stockholders' Equity

Tranche A, Tranche B and Preferred Tranche C Unit Issuance

Until the Company's IPO, the operations of Holdings, the Company's predecessor, were governed by the provisions of the Third and Amended and Restated Limited Liability Company Agreement effective October 3, 2016 ("Holdings LLC Agreement") and the Company had two classes of voting membership interests outstanding, the Tranche A Equity Units and the Tranche C Equity Units. In connection with the Reorganization, on May 29, 2014, the following Tranche A Equity Units were issued:

- 62.4 million Tranche A Equity Units were issued to certain members that had made historical capital contributions to Extraction through PRL at a price of $1.02 per unit for gross proceeds of $63.4 million; and,

- 14.5 million Tranche A Equity Units were issued to certain members to settle $39.0 million of Extraction convertible notes at a price of $2.68 per unit for gross proceeds of $39.0 million.

Additionally, on May 29, 2014, 75.6 million Tranche A Equity Units were issued to new and existing members in exchange for additional capital contributions at a price of $2.68 per unit for gross proceeds of $202.9 million.

On August 20, 2014, Holdings issued an additional 74.5 million Tranche A Equity Units to new and existing members in exchange for additional capital contributions at a price of $2.68 per unit for gross proceeds of $199.9 million.

On February 18, 2015, Holdings issued 15.3 million Tranche B Equity Units to certain Members at a purchase price of $3.25 per unit for gross proceeds of $49.5 million. The Tranche B Equity Unit holders were granted certain rights in Holdings' LLC Agreement. Included was a right to exchange the Tranche B Equity Units for new equity units at a price of $3.25 per unit if the Company issues any equity units with rights, preferences or obligations different from the Tranche B Units on or prior to May 14, 2015.

On March 10, 2015, Holdings issued 32.5 million Tranche C Equity Units to certain new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $105.7 million and each Tranche B Equity Unit was reclassified as a Tranche C Equity Unit, such that no Tranche B Equity Units remain outstanding. The Tranche C Equity Unit holders were granted certain rights in Holdings' LLC Agreement. Included with these rights were, (1) the right to receive their invested capital prior to any distribution to any other unit holders, (2) the right to receive additional Tranche C units under specified circumstances contingent upon an initial public offering or certain change of control events and (3) the right to approve the issue of equity units with any rights or preferences that are senior to the rights and preferences of the Tranche C Equity Units.

On September 24, 2015, Holdings issued 22.9 million Tranche C Equity Units to Members at a purchase price of $3.25 per unit for gross proceeds of $74.3 million.

On October 13, 2015, Holdings issued 7.9 million Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $25.7 million.

In April 2016 and June 2016, Holdings issued 35.8 million Preferred Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $116.4 million. The proceeds of the April and June 2016 Offering were used for general business purposes, including to repay amounts borrowed under the Company's credit facility.

In July 2016, Holdings issued an additional 1.5 million Preferred Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $5.0 million. The proceeds of the July 2016 Offering were used for general business purposes, including to repay amounts borrowed under the Company's credit facility.

Holdings incurred equity issuance costs related to the aforementioned equity offerings of $15.5 million from inception through the IPO. These equity issuance costs were recorded as a reduction to Members' and Stockholders' Equity.

Restricted Unit Awards ("RUAs")

Under the Holdings LLC Agreement, the Company could grant RUAs to employees, non-employee managers and consultants. RUAs were nonvoting membership interests in the Company and are subject to certain vesting and forfeiture conditions, but have equal rights and preferences to the Tranche A Equity Units in all other regards. See *Note 11 — Unit and Stock-Based Compensation* for additional information.

Promissory Notes

In May 2014, the Company received full recourse promissory notes from two officers under which the Company advanced $5.4 million to the employees to meet their capital contributions. The promissory notes were due on May 29, 2021, or earlier in the event of termination or certain change in control events as stipulated in the individual promissory notes and any distributions of capital contributions are considered mandatory prepayments. The promissory notes have a stated interest rate of LIBOR plus 1% per annum. The promissory notes are recorded as a reduction of members' equity.

In September 2016, the Company redeemed 1.2 million units from two of its executive officers, for an aggregate purchase price of $7.8 million. On the same date, the executive officers used $5.6 million of the redemption value to settle in full and terminate their obligations under the promissory notes, including accrued interest thereon.

Series A Preferred Units

On October 3, 2016, the Company issued $75.0 million in Series A Preferred Units (the "Series A Preferred Units") to fund a portion of the purchase price for the October 2016 Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. All holders of Series A Preferred Units were also members of Holdings. The Company used $90.0 million of the net proceeds from its IPO to redeem the Series A Preferred Units in full on October 17, 2016, including a premium of $15.0 million which is recorded within additional paid in capital in the consolidated statement of changes in members' and stockholders' equity. For further discussion on the October 2016 Acquisition, please refer to *Note 4 — Acquisitions.*

Series A Preferred Stock and Series B Preferred Units

On October 3, 2016, the Company issued $185.3 million in convertible preferred securities ("Series B Preferred Units") to fund a portion of the purchase price for the October 2016 Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and the Company had the ability to pay up to 50% of the quarterly dividend in kind. For the year ended December 31, 2016, the Company paid $0.7 million of dividends associated with the Series B Preferred Units. The Company did not make any payments in kind on the Series B Preferred Units from the date of issuance of the Series B Preferred Units through the Offering. The Series B Preferred Units converted in connection with the closing of the IPO into 185,280 shares of Series A Convertible Preferred Stock (the "Series A Preferred Stock") that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and the Company has the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are paid in cash). For the year ended December 31, 2016, the Company accrued $2.2 million of dividends associated with the Series A Preferred Stock, which were paid in January 2017. The Company did not make any payments in kind on the Series A Preferred Stock from the date of the Offering through December 31, 2016. Beginning on or after the later of (a) 90 days after the closing of the Offering and (b) the earlier of 120 days after the closing of the Offering and the expiration of the lock-up period contained in the underwriting agreement entered into in connection with the Offering ("Lock-Up Period End Date"), the Series A Preferred Stock will be convertible into shares of our common stock at the election of the holders of the Series A Preferred Stock ("Series A Preferred Holders") at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the Offering, the Company may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of the Company's common stock trades at or above a certain premium to the Company's initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference.

Initial Public Offering

On October 17, 2016, the Company completed its initial public offering, issuing 38.3 million shares of common stock, par value $0.01 per share ("common stock"), which includes the full exercise of the underwriters' over-allotment option of 5.0 million shares at a price of $19.00 per share. The estimated net proceeds of the offering were $681.0 million, after deducting underwriting discounts and commissions and offering expenses, of approximately $47.3 million. The proceeds from the Offering were used to (i) redeem in full the Series A Preferred Units for $90.0 million and (ii) to repay borrowings under the Company's revolving credit facility for $291.6 million. The remaining net proceeds will be used for general corporate purposes, including to fund 2017 capital expenditures. The material terms of the Offering are described in the Company's final prospectus, dated October 11, 2016 and filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on October 13, 2016.

In connection with the IPO, Holdings merged with and into Extraction and Extraction was the surviving entity to the merger, with the equity holders in Holdings, other than the holders of the Series B Preferred Units (which were converted in connection with the closing of the Offering into shares of Series A Preferred Stock as defined below), but including the holders of RUAs and incentive units, receiving an aggregate of 108.5 million shares of common stock, with the allocation of such shares among Holdings' equity holders determined by reference to the Company's implied valuation based on the 10-day volume weighted average price of the common stock following the closing of the Offering, in accordance with the distribution mechanics set forth in the Holdings LLC Agreement. As a result of the Offering, there were 146.8 million common shares outstanding.

Private Placement of Common Stock

On December 15, 2016, the Company completed the issuance of 25.0 million shares of common stock, at a price of $18.25 per share, in connection with the Private Placement (the "Private Placement"). The Private Placement resulted in approximately $457.0 million of gross proceeds and approximately $441.9 million of net proceeds, after deducting placement agent commissions and offering expenses. Proceeds from the Private Placement will be used for general corporate purposes, including to fund the Company's 2017 capital expenditures. As a result of the Private Placement, there are 171.8 million common shares outstanding.

Note 10—Income Taxes

Holdings, the Company's accounting predecessor, was a limited liability company that was not subject to U.S. federal income tax. As part of the Corporate Reorganization, the members of Holdings exchanged all of their member units for shares of the Company's common stock. For additional discussion on the Corporate Reorganization, see *Note 1 — Business and Organization.* As a result of the Corporate Reorganization, the Company identified and established the deferred tax assets and liabilities for differences between the book and tax basis of Holdings. The Company recorded a net deferred tax liability of approximately $135.3 million. As this Corporate Reorganization is being accounted for as a transaction under common control the offset of the net deferred tax liability was recorded to additional paid-in capital within the consolidated balance sheet.

The components of the income tax expense (benefit) were as follows (in thousands):

	For the Year Ended December 31, 2016
Current:	
Federal	$ —
State, net of federal benefit	—
Total current income tax benefit	$ —
Deferred:	
Federal	$ (26,962)
State, net of federal benefit	(2,318)
Total deferred income tax benefit	$ (29,280)
Income tax benefit	$ (29,280)

The following table reconciles the income tax expense (benefit) with income tax expense at the federal statutory rate (in thousands):

	For the Year Ended December 31, 2016
Loss before income taxes	(485,281)
Federal income taxes at statutory rate	(169,849)
Net loss prior to Corporate Reorganization	80,463
State income taxes, net of federal benefit	(2,318)
Nondeductible stock-based compensation	62,284
Other	140
Income tax expense (benefit)	(29,280)
Net loss	$ (456,001)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	As of December 31, 2016
Deferred Tax Assets:	
Net operating loss carryforward	$ 35,719
Commodity derivatives	24,068
Other	17,133
Total deferred tax assets	76,920
Deferred Tax Liabilities:	
Excess basis of oil and gas properties	(182,946)
Total deferred tax liabilities	(182,946)
Deferred Tax Liability, net	$ (106,026)

Management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgement. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. The Company has net operating loss carryforwards (NOLs) for U.S. income tax purposes that have been generated from our operations of approximately $94.0 million. These NOLs are scheduled to expire if not utilized in year 2037.

The utilization of such NOL carryforwards may be limited upon the occurrence of certain ownership changes as stipulated in Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”). As of December 31, 2016, the

Company determined that the statutory provision of Section 382 will not limit the Company's ability to realize future tax benefits. As of December 31, 2016, the Company believes it will be able to generate sufficient future taxable income within the carryforward period and accordingly, believes that it is more likely than not that its deferred income tax assets will be fully realized. The Company files income tax returns in the U.S. federal jurisdiction and in Colorado. The statute of limitations related to the 2016 tax return is open through 2020, however, the ability for the tax authority to adjust the NOL will continue until three years after the NOL is utilized.

As of December 31, 2016, the Company believes that it has no liability for uncertain tax positions. If the Company were to determine there were any uncertain tax positions, the Company would recognize the liability and related interest and penalties within income tax expense. As of December 31, 2016, the Company had no provision for interest or penalties related to uncertain tax positions.

Note 11—Unit and Stock-Based Compensation

Holdings' Membership Unit Incentive Plan

On May 29, 2014, Holdings adopted the 2014 Membership Unit Incentive Plan ("2014 Plan"). The 2014 Plan provided for the compensation of employees, non-employee managers and consultants of the Company and its affiliates through grants of restricted unit awards ("Holdings' RUAs") and incentive units ("Holdings' Incentive Units"). The 2014 Plan was terminated as a result of the Corporate Reorganization in October 2016.

Holdings' RUAs

At the Reorganization through December 31, 2016, the following Holdings' RUA activity occurred related to the Company's employees and non-employee consultants:

- 3.4 million Holdings' RUAs were granted to each holder of PRL RUAs as part of the Reorganization, (as defined below under the heading "PRL RUAs");
- 3.5 million Holdings' RUAs were granted to certain Company employees and consultants to keep their equity ownership whole as part of the Reorganization;
- 1.4 million Holdings' RUAs were granted to certain members of Extraction management who participated in Extraction's Net Profits Interest Bonus Plan, which was terminated on May 29, 2014 as part of the Reorganization;
- 1.9 million Holdings' RUAs were granted to certain Company employees that were hired subsequent to the Reorganization; and
- 1.5 million Holdings' RUAs were granted to certain officers.

Holdings' RUAs vested over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. The vesting period for the 3.4 million Holdings' RUAs granted to holders of PRL RUAs was carried over from the original PRL RUA grants; as such, 0.2 million Holdings' RUAs were vested on May 29, 2014. The vesting period for all other Holdings' RUAs begins on the grant date. The Company estimated fair value of the RUAs on their grant date based upon estimated volatility, market comparable risk free rate, estimated forfeiture rate and a discount for lack of marketability. Grant date fair value was determined based on the value of Holdings' Equity Units on the date of the grant. Due to a lack of historical data, the Company used the experience of other entities in the same industry to estimate a forfeiture rate. Expected forfeitures are then included as part of the grant date estimate of compensation cost.

The Company recorded $16.8 million, $5.3 million, and $3.7 million of unit-based compensation costs related to Holdings' RUA grants for the years ended December 31, 2016, 2015 and 2014, respectively. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. No tax benefit related to unit-based compensation was recognized in the consolidated statements of operations and no unit-based compensation was capitalized for years ended December 31, 2016, 2015 and 2014. In connection with the IPO, vesting was accelerated on all of the Holdings' RUAs and there is no unrecognized compensation cost related to unvested RUAs granted to employees.

Of the 3.4 million Holdings' RUAs granted to holders of PRL RUAs in connection with the Reorganization, 1.3 million were granted to PRL employees or consultants. The Company does not record any unit-based compensation expense related to these awards because PRL employees or consultants do not provide services to the Company.

Of the 3.5 million Holdings' RUAs granted to certain employees and consultants to keep their equity ownership whole as part of the Reorganization, 1.3 million were granted to PRL employees or consultants. The Company does not record any unit-based compensation expense related to these awards because PRL employees or consultants do not provide services to the Company.

The following table summarizes the Holdings' RUA activity from May 29, 2014 through December 31, 2016 and provides information for Holdings' RUAs outstanding at the dates indicated:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RUAs at May 29, 2014	8,353,616	$ 2.21
Granted	1,705,000	$ 2.25
Forfeited	(21,826)	$ 2.21
Vested	(670,894)	$ 2.21
Non-vested RUAs at December 31, 2014	9,365,896	$ 2.22
Granted	196,047	$ 2.68
Forfeited	(53,063)	$ 2.21
Vested	(3,197,638)	$ 2.22
Non-vested RUAs at December 31, 2015	6,311,242	$ 2.23
Granted	1,531,542	$ 5.84
Forfeited	(181,817)	$ 2.68
Vested	(7,660,967)	$ 2.94
Non-vested RUAs at December 31, 2016	—	$ —

PRL RUAs

Prior to the Reorganization, PRL granted RUAs to certain employees, including Extraction employees ("PRL RUAs"). Subsequent to the Reorganization, Extraction's employees retained the PRL RUAs. PRL RUAs vested over a three year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of PRL's Equity Units on the date of the grant. PRL uses its past experience to estimate a forfeiture rate and expected forfeitures are included as part of the grant date estimate of compensation cost.

The Company recorded $0.5 million, $0.8 million, and $0.8 million of unit-based compensation costs related to PRL RUA grants for the years ended December 31, 2016, 2015 and 2014, respectively. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2016, there was no unrecognized compensation cost related to the PRL RUAs as all awards were fully vested.

Holdings' Incentive Units

In accordance with the 2014 Plan and the Holdings LLC Agreement, Holdings issued 3.0 million Holdings' incentive units to certain members of management in the fourth quarter of 2015. No Holdings' Incentive Units were issued during 2016. All of Holdings' Incentive Units were non-voting and subject to certain vesting and performance conditions. The Holdings' Incentive Units vested over a three year service period, with 25%, 25% and 50% of the units vesting in year 1, year 2 and year 3, respectively (with vesting between the first and third anniversaries occurring pro-rata based on the number of full months elapsed since the last vesting date), and in full upon a change of control, as defined in the Holdings LLC Agreement. The Holdings' Incentive Units were accounted for as liability awards under ASC 718, *Compensation-Stock Compensation*, with compensation expense based on period-end fair value.

In connection with the IPO, the Board of Managers of Holdings accelerated the vesting of the Holdings' Incentive Units. The Company's IPO and change of control triggered the conversion of these units into approximately 9.1 million common shares of the Company based on the 10-day volume weighted average price of the Company's common stock following its IPO as set forth in the Holdings Third Amended and Restated LLC Agreement. For the year ended December 31, 2016, the Company recognized approximately $172.1 million in non-cash, share-based compensation expense in connection with the conversion of the Holdings' Incentive Units into the Company's common stock. No incentive compensation expense was recorded for the years ended December 31, 2015 and 2014 because it was not probable that the performance criterion would be met.

Incentive Restricted Stock Units ("Incentive RSUs")

In November 2016, after the Holdings' Incentive Units were converted to the 9.1 million shares of common stock, holders of the Holding's Incentive Units contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vest over a three year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $2.4 million of stock-based compensation costs related to Incentive RSUs for the year ended December 31, 2016 and no stock-based compensation costs related to Incentive RSUs for the years ended December 31, 2015 and 2014. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2016, there was $53.1 million of total unrecognized compensation cost related to the unvested Incentive RSUs granted to certain employees that is expected to be recognized over a weighted average period of 2.9 years.

The following table summarizes the Incentive RSU activity from January 1, 2016 through December 31, 2016 and provides information for Incentive RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Incentive RSUs at January 1, 2016	—	$ —
Granted	2,717,968	$ 20.45
Forfeited	(3,600)	$ 20.45
Vested	—	$ —
Non-vested Incentive RSUs at December 31, 2016	2,714,368	$ 20.45

Extraction Long Term Incentive Plan

In October 2016, the Board of Managers adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the "2016 Plan" or "LTIP"), pursuant to which employees, consultants, and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards, and performance awards intended to align the interests of participants with those of stockholders. In accordance with the terms of the LTIP, 20.2 million shares of common stock have been reserved for issuance pursuant to awards under the LTIP. In October 2016, and in connection with the Offering, Extraction granted awards under the LTIP to certain directors and officers, including stock options and restricted stock units.

Stock Options

Expense on the stock option is recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options were measured at the grant date using the Black Scholes valuation model. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company's peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the LTIP vest ratably over 3 years, are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company issues new shares.

The Company recorded $2.9 million of stock-based compensation costs related to the stock options for the year ended December 31, 2016. The Company did not record any stock-based compensation expense related to stock options for the years ended December 31, 2015 and 2014. As of December 31, 2016, there was $36.5 million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted-average period of 2.8 years.

The following table summarizes the assumptions used for the Black-Scholes valuation model to calculate the stock-based compensation expense for the years presented.

		For the Year Ended December 31, 2016
Risk free rates		1.4 %
Dividend yield		—
Expected volatility		47.2 %
Expected life (in years)		6.0
The weighted average fair value at the date of grant for stock options granted is as follows:		
Weighted average per share	$	8.75
Total options granted		4,500,000
Total weighted average fair value of shares granted (in thousands)	$	39,375

The following table summarizes the stock option activity from January 1, 2016 through December 31, 2016 and provides information for stock options outstanding at the dates indicated.

	Number of Shares		Weighted Average Exercise Price
Non-vested Stock Options at January 1, 2016	—	$	—
Granted	4,500,000	$	19.00
Forfeited	—	$	—
Vested	—	$	—
Non-vested Stock Options at December 31, 2016	4,500,000	$	19.00

Restricted Stock Units ("RSUs")

Restricted stock units granted under the LTIP ("RSUs") vest over either a one or three year service period, with 100% or 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $5.5 million of stock-based compensation costs related to RSUs for the year ended December 31, 2016 and no stock-based compensation costs related to RSUs for the years ended December 31, 2015 and 2014. As of December 31, 2016, there was $63.8 million of total unrecognized compensation cost related to the unvested RSUs granted to certain employees that is expected to be recognized over a weighted average period of 2.5 years.

The following table summarizes the RSU activity from January 1, 2016 through December 31, 2016 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2016	—	$ —
Granted	3,237,500	$ 21.41
Forfeited	—	$ —
Vested	—	$ —
Non-vested RSUs at December 31, 2016	3,237,500	$ 21.41

Note 12—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) by the weighted-average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings of the Company.

EPS for the year ended December 31, 2016 is calculated for the period from October 12, 2016, the effective date of the Corporate Reorganization, to December 31, 2016. EPS information is not applicable for reporting periods prior to the Corporate Reorganization. The Company uses the "if-converted" method to determine potential dilutive effects of Series A Preferred Stock and the treasury method to determine the potential dilutive effects of outstanding restricted stock awards and stock options. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the period from October 12, 2016 to December 31, 2016. Please refer to *Note 1 — Business and Organization* and *Note 9 — Members' and Stockholders' Equity* for additional discussion regarding the Corporate Reorganization.

The components of basic and diluted EPS were as follows:

	From October 12, 2016 to December 31, 2016
Basic and Diluted EPS (in thousands, except per share data)	
Net Loss	$ (226,107)
Less: Adjustment to reflect Series A Preferred Stock dividend	(2,958)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,041)
Net loss used to compute net loss per share	$ (230,106)
Weighted Average Common Shares Outstanding (1)	
Basic and diluted	149,029
Net Loss per Common Share	
Basic and diluted	$ (1.54)

(1) For the period of October 12 through December 31, 2016, 7,737,500 potentially dilutive restricted stock awards and stock options outstanding for the period were not included in the EPS calculation above, as such securities had an anti-dilutive effect on EPS. Additionally, the 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.

Note 13—Commitments and Contingencies

Leases

The Company leases two office spaces in Denver, Colorado, one office space in Greeley, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2026, respectively. The Greeley and Houston leases expire on August 19, 2019 and October 31, 2017, respectively. Total rental commitments under non-cancelable leases for office space were $21.1 million at December 31, 2016. The future minimum lease payments under these non-cancelable leases are as follows: $2.5 million in 2017, $2.5 million in 2018, $2.4 million in 2019, $2.1 million in 2020, $2.1 million in 2021 and $9.5 million thereafter. Rent expense was $1.9 million, $1.1 million, and $0.4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

On June 4, 2015, the Company subleased the remaining term of one of its Denver office leases that expires February 29, 2020. The sublease will decrease the Company's future lease payments by $0.7 million.

Drilling Rigs

As of December 31, 2016, the Company was subject to commitments on four drilling rigs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $5.0 million as of December 31, 2016, as required under the terms of the contracts. In March 2015, the Company early terminated one of its drilling rig contracts for approximately $1.7 million, which was recorded in the consolidated statements of operations within the other operating expenses line item. In February 2016, the Company provided notice to terminate one of its drilling rigs that was subject to commitment at December 31, 2015. As part of this termination, the Company was obligated to pay $1.0 million in the second quarter of 2016. In January 2017, the Company provided notice for termination on one drilling rig and paid no termination fees.

In January 2017, the Company entered into an additional commitment on an additional drilling rig, which is anticipated to be placed in service during the third quarter of 2017. In the event of early termination on this contract the Company would be obligated to pay an aggregate amount of approximately $5.7 million, as required under the terms of the contracts.

Delivery Commitments

As of December 31, 2016, the Company's oil marketer was subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven, and 58,000 Bbl/d in years eight through ten and any failure to satisfy the minimum volume commitments is taken into account when calculating the revenue the Company receive from the oil marketer. The Company also had two long-term crude oil gathering commitments. The first has a term of five years for 5,000 Bbl/d in year one and 3,800 Bbl/d in years two through five and the second has a term of seven years for 4,000 Bbl/d in years one through three, 2,500 Bbl/d in year four, and 1,500 Bbl/d in years five through seven. The aggregate amount of estimated payments under these agreements was $951.2 million.

In collaboration with several other producers and DCP, the Company has agreed to participate in the expansion of natural gas gathering and processing capacity in the DJ Basin. The plan includes a new 200 MMcf per day processing plant as well as the expansion of a related gathering system, both currently expected to be completed by late 2018, although the start-up date is undetermined at this time. Our share of the commitment will require 51.5 MMcf per day to be delivered after the plant in-service date for a period of 7 years. This contractual obligation can be reduced by our proportionate share of the collective volumes delivered to the plant by other producers in the DJ Basin that are in excess of the total commitment. Our volume shortfall fee would range between $0.95 and $1.50 per Mcf, in the event the Company does not meet our minimum volume commitment per month. At this time, the Company is unable to reasonably estimate the amount of potential volume shortfalls due to the volume pooling with other producers in the DJ Basin.

None of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers. The Company believes that its future production is adequate to meet its commitments. If for some reason the Company's production is not sufficient to satisfy its commitments, the Company expects to be able to purchase volumes in the market or make other arrangements to satisfy its commitments.

Acquisition of Undeveloped Leasehold Acreage

As of December 31, 2016, the Company is obligated under an agreement with an unrelated third party to pay approximately $59.6 million in 2017 for the acquisition of undeveloped leasehold acreage.

General

The Company is subject to contingent liabilities with respect to existing or potential claims, lawsuits, and other proceedings, including those involving environmental, tax, and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters and its experience in contesting, litigating, and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which management currently believes will not have a material effect on the Company's financial position, results of operations, or cash flows.

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost or the Company may be required to pay damages if certain performance conditions are not met.

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. Management is unaware of any pending litigation brought against the Company requiring the reserve of a contingent liability as of the date of this filing.

The Company is currently in discussions with the Colorado Department of Public Health and Environment ("CDPHE") regarding its July 2015 Compliance Advisory issued to the Company, which alleged air quality violations at three Company facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. The CDPHE subsequently expanded its investigation to several additional Company facilities and, more recently, has indicated to the Company that it is further expanding its investigation to the Company's other facilities in Colorado and intends to seek a field-wide administrative settlement of these issues. The Company cannot predict the outcome of this matter at this time.

Note 14—Related Party Transactions

Office Lease with Related Affiliate

In April 2016, the Company subleased office space to Star Peak Capital, LLC, of which a member of the board of managers is an owner, for $1,400 per month. The sublease commenced on May 1, 2016 and expires on February 28, 2020.

Units Repurchased from Officer

In May 2016, the Company repurchased 60,605 Tranche A Units and 82,578 Tranche C Units from its former Chief Accounting Officer, for $3.25 per unit for an aggregate purchase price of approximately $0.5 million.

Promissory Notes

In May 2014, the Company received full recourse promissory notes from two officers under which the Company advanced $5.4 million to the employees to meet their capital contributions. The promissory notes were due on May 29, 2021, or earlier in the event of termination or certain change in control events as stipulated in the individual promissory notes and any distributions of capital contributions were considered mandatory prepayments. The promissory notes had a stated interest rate of LIBOR plus 1% per annum. The promissory notes were recorded as a reduction of members' equity.

In September 2016, the Company redeemed 1.2 million units from two of its executive officers, for an aggregate purchase price of $7.8 million. On the same date, the executive officers used $5.6 million of the redemption value to settle in full and terminate their obligations under the promissory notes, including accrued interest thereon.

Second Lien Notes

Several lenders of Second Lien Notes were also members of Holdings. Of the $430.0 million formerly outstanding on the Second Lien Notes, members held approximately $311.7 million. These members were paid $314.8 million upon repayment and termination of the Second Lien Notes, including the prepayment penalty.

Senior Notes

Several lenders of Senior Notes are also members of Holdings. As of the initial issuance of the $550.0 million principal amount on the Senior Notes, members held $168.5 million.

Series A Preferred Units

All holders of the $75.0 million of Series A Preferred Units were also members of Holdings. The Company used $90.0 million of the net proceeds from its IPO to redeem the Series A Preferred Units in full on October 17, 2016, which included a premium of $15.0 million.

Series A Preferred Stock and Series B Preferred Units

As of the initial issuance of the $185.3 million of Series B Preferred Units, members of Holdings held approximately $135.3 million. Upon closing of the IPO, members of Holdings held $185.3 million of the Series A Preferred Stock.

Private Placement of Common Stock

Of the $457.0 million of common stock sold, entities that already held common stock purchased $251.4 million of additional common stock, including affiliates of Blackrock, Inc. and Fidelity Investments, which purchased 750,000 and 1,753,370 shares for $13.7 million and $32.0 million, respectively.

Due to Related Party

For the year ended December 31, 2014, PRL paid for certain general and administrative expenses, which included salary and related benefits, office rent, insurance premiums and other general and administrative costs of $2.0 million. The Company repaid $1.8 million of these expenses during the year ended December 31, 2014 and recorded a payable due to related party in the amounts of $0.2 million at December 31, 2014. The remaining $0.2 million was repaid in April 2015. For the years ended December 31, 2015 and 2016, PRL did not pay for any of the Company's general and administrative expenses and there was no remaining payable due to related party.

Payment for Certain Services to a Related Affiliate

In 2014, the Company entered into an agreement for certain services provided in connection with obtaining debt. A member of our board of managers is an independent contractor for the Company that provided these services. The services were completed in 2014 in connection with facilitating the borrowings under the Second Lien Notes. The Company agreed to make aggregate payments of approximately $2.1 million for these services and the amount was recorded in debt issuance costs and will be amortized using the effective interest method. As of December 31, 2015, the entire amount of $2.1 million was paid.

Related Party—Note Payable

In connection with the Reorganization, the balance of Extraction's Related Party—Note Payable, including accrued interest, was converted into equity of $62.4 million in May 2014. Interest expense incurred on the Related Party—Note Payable was $0.3 million for the year ended December 31, 2014.

Convertible Notes

In April and May 2014, certain members were issued $39.0 million of convertible notes, with an interest rate of 6% per annum. In connection with the Reorganization, Extraction's convertible notes were converted into equity in May 2014. For the year ended December 31, 2014, the Company incurred interest expense of $0.2 million on the convertible notes.

Related Party—Employees

Mr. Troy Owens, brother of Mr. Matthew R. Owens, our President and a member of our Board of Directors, is employed by the Company as an engineer. Consistent with market compensation for his services, Mr. Troy Owens received approximately $165,000 in aggregate cash compensation relating to the fiscal year ended December 31, 2016. In addition, Mr. Troy Owens received certain long-term incentives during the same period in the form of restricted stock units that vest over a period of three years.

Note 15—Supplemental Oil and Gas Reserve Information (Unaudited)

Results of Operations for Oil, Natural Gas and NGL Producing Properties

The following are the results of operations (in thousands) of the Company's oil and gas producing activities, before corporate overhead and interest expenses. The Company assumed a statutory tax rate of 38% for all years presented, although the Company was not subject to federal and state income taxes prior to the Corporate Reorganization.

	For the Year Ended December 31,		
	2016	2015	2014
Revenues	$ 278,089	$ 197,750	$ 92,840
Operating Expenses:			
Production expenses	82,773	47,663	14,810
Exploration expenses	36,422	18,636	126
Depletion and accretion	203,073	144,228	33,825
Impairment of proved properties	22,438	12,207	—
Results of operations before income tax expense	(66,617)	(24,984)	44,079
Income tax expense (benefit)	(25,314)	(9,494)	16,750
Results of Operations	$ (41,303)	$ (15,490)	$ 27,329

Oil, Natural Gas and NGL Reserve Quantities (Unaudited)

The reserves at December 31, 2016, 2015 and 2014 presented below were prepared by the independent engineering firm Ryder Scott Company, L.P. All reserves are located within the DJ Basin. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petro physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The following table sets forth information for the years ended December 31, 2016, 2015 and 2014 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil Mbbls	Natural Gas MMcf	NGL Mbbls	MBoe Total
Balance as of December 31, 2013	123.9	673.0	88.8	324.9
Revisions of previous estimates	(300.3)	3,493.9	755.9	1,037.9
Purchase of reserves	17,968.1	82,051.7	9,219.1	40,862.5
Extensions, discoveries, and other additions	28,395.4	82,861.5	9,712.5	51,918.2
Sale of reserves	—	—	—	—
Production	(1,022.2)	(2,664.0)	(325.3)	(1,791.5)
Balance as of December 31, 2014	45,164.9	166,416.1	19,451.0	92,352.0
Revisions of previous estimates	(2,961.0)	(2,825.8)	2,281.9	(1,150.1)
Purchase of reserves	11,831.7	64,392.7	7,533.3	30,097.1
Extensions, discoveries, and other additions	23,098.7	85,781.0	11,663.4	49,058.9
Sale of reserves	(1,688.5)	(10,357.1)	(1,212.1)	(4,626.8)
Production	(3,945.6)	(10,823.0)	(1,334.6)	(7,084.0)
Balance as of December 31, 2015	71,500.2	292,583.9	38,382.9	158,647.1
Revisions of previous estimates	(15,576.8)	35,803.1	1,988.8	(7,620.8)
Purchase of reserves	18,473.6	78,761.6	9,680.7	41,281.2
Extensions, discoveries, and other additions	21,885.4	120,798.3	14,679.9	56,698.5
Sale of reserves	—	—	—	—
Production	(5,287.4)	(20,211.5)	(2,284.0)	(10,940.0)
Balance as of December 31, 2016	90,995.0	507,735.4	62,448.3	238,066.0
Proved Developed Reserves, included above				
Balance as of December 31, 2013	123.9	673.0	88.8	324.9
Balance as of December 31, 2014	9,755.6	35,580.1	4,158.8	19,844.5
Balance as of December 31, 2015	14,248.6	53,011.7	7,058.3	30,142.3
Balance as of December 31, 2016	17,158.0	107,918.0	13,354.0	48,498.4
Proved Undeveloped Reserves, included above				
Balance as of December 31, 2013	—	—	—	—
Balance as of December 31, 2014	35,409.3	130,836.0	15,292.2	72,507.5
Balance as of December 31, 2015	57,251.5	239,572.2	31,324.6	128,504.8
Balance as of December 31, 2016	73,837.0	399,817.4	49,094.3	189,567.5

- The values for the 2016 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2016. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $42.75 per barrel (West Texas Intermediate price) for crude oil and NGLs and $2.49 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2016 was $34.91 per barrel for oil, $1.39 per Mcf for natural gas and $11.63 per barrel for NGLs.

- The values for the 2015 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2015. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $50.28 per barrel (West Texas Intermediate price) for crude oil and NGLs and $2.58 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2015 was $43.28 per barrel for oil, $2.11 per Mcf for natural gas and $10.65 per barrel for NGLs.

- The values for the 2014 oil, natural gas and NGL reserves are based on the 12 month arithmetic average of the first day of the month prices for the period from January through December 31, 2014. The unweighted arithmetic average first-day-of-month prices for the prior twelve months were $94.99 per barrel (West Texas Intermediate price) for crude oil and NGLs and $4.35 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2014 was $84.99 per barrel for oil, $3.97 per Mcf for natural gas and $28.39 per barrel for NGLs.

For the year ended December 31, 2016, the Company had downward revisions of previous estimates of 7,620.8 MBoe. As a result of ongoing drilling and completion activities during 2016, the Company reported extensions, discoveries, and other additions of 56,698.5 MBoe. Additionally, during 2016 the Company purchased reserves of 41,281.2 MBoe.

For the year ended December 31, 2015, the Company had downward revisions of previous estimates of 1,150.1 MBoe. As a result of ongoing drilling and completion activities during 2015, the Company reported extensions, discoveries, and other additions of 49,058.9 MBoe. Additionally, during 2015 the Company purchased reserves of 30,097.1 MBoe.

For the year ended December 31, 2014, the Company had upward revisions of previous estimates of 1,037.9 MBoe. These revisions are primarily the result of well performance exceeding previous estimates. As a result of ongoing drilling and completion activities during 2014, the Company reported extensions, discoveries, and other additions of 51,918.2 MBoe. Additionally, during 2014 the Company purchased reserves of 40,862.5 MBoe.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves

The Company follows the guidelines prescribed in ASC 932, *Extractive Activities-Oil and Gas* for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and gas properties as of December 31 of the years presented. These estimates were prepared by Ryder Scott Company L.P., independent petroleum engineers.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions. (2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves. (3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred. (4) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following are the principal sources of change in the standardized measure (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Future crude oil, natural gas and NGL sales	$ 4,610,848	$ 4,119,888	$ 5,051,640
Future production costs	(1,429,202)	(1,193,560)	(1,173,237)
Future development costs	(1,579,628)	(1,141,330)	(1,017,668)
Future income tax expense	(42,859)	—	—
Future net cash flows	$ 1,559,159	$ 1,784,998	$ 2,860,735
10% annual discount	(836,163)	(949,115)	(1,473,263)
Standardized measure of discounted future net cash flows(1)	$ 722,996	$ 835,883	$ 1,387,472

(1) The Company's calculations of the standardized measure of discounted future net cash flows does not include the effect of estimated future income tax expenses for the years ended December 31, 2015 and 2014 as the Company was a limited liability company and not subject to income taxes. For the year ended December 31, 2016, future income tax expenses in the Company's calculation of the standardized measure of discounted future net cash flows are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and gas properties, other deductions, credit and allowances relating to the Company's proved reserves. For purposes of the standardized measure calculation, it was assumed that all of the Company's operations are attributable to the Company's oil and gas assets. If the Company had been subject to entity-level income taxation, the unaudited pro forma future income tax expense at December 31, 2015 and 2014 would have been $327.9 million and $791.0 million, respectively, and the unaudited standardized measure would have been $680.3 million and $992.5 million, respectively.

The following summary sets forth the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC 932, *Extractive Activities-Oil and Gas* (in thousands):

	For the Year Ended December 31,		
	2016	2015	2014
Balance at beginning of period	$ 835,883	$ 1,387,472	$ 7,816
Sales of crude oil, natural gas and NGL, net	(195,316)	(150,087)	(78,030)
Net change in prices and production costs	(325,236)	(1,292,364)	(94,884)
Net change in future development costs	(49,213)	175,944	14,149
Extensions and discoveries	96,982	284,216	787,910
Acquisitions of reserves	156,675	240,989	666,887
Sale of reserves	—	(50,018)	—
Revisions of previous quantity estimates	19,161	(28,391)	19,606
Previously estimated development costs incurred	123,085	102,060	42,100
Net changes in income taxes	(17,611)	—	—
Accretion of discount	83,588	156,723	28,995
Other	(5,002)	9,339	(7,077)
Balance at end of period	$ 722,996	$ 835,883	$ 1,387,472

Note 16—Unaudited Quarterly Financial Data

The following is a summary of the unaudited quarterly financial data for each of the quarters from first quarter 2015 through fourth quarter 2016 (in thousands, except per share data). Historical results are not necessarily indicative of the results to be expected in future periods. You should read this data together with our consolidated financial statements and the related notes included elsewhere in this Annual Report:

	Three Months Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Oil, Natural gas and NGL sales	$ 45,133	$ 65,364	$ 72,902	$ 94,690
Operating Income (Loss) [(1)]	$ (16,635)	$ (3,593)	$ 4,556	$ 5,640
Net Loss	$ (45,519)	$ (127,614)	$ (37,267)	$ (245,601)
Basic and Diluted Loss Per Common Share [(2)]				$ (1.54)

	Three Months Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Oil, Natural gas and NGL sales	$ 36,559	$ 56,223	$ 48,846	$ 56,122
Operating Income (Loss) [(1)]	$ 3,242	$ 11,014	$ (4,401)	$ (6,315)
Net Income (Loss)	$ (18,743)	$ (37,967)	$ 18,650	$ (9,204)

(1) Oil, Natural gas and NGL sales revenue less lease operating expenses, production taxes and depreciation, depletion, amortization and accretion.

(2) EPS for the year ended December 31, 2016 is calculated for the period from October 12, 2016, the effective date of the Corporate Reorganization, to December 31, 2016. EPS information is not applicable for reporting periods prior to the Corporate Reorganization.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2016. 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, 2016 at the reasonable assurance level.

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

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

A holder of our common stock who wishes to present a proposal for inclusion in our proxy statement for the 2017 Annual Meeting pursuant to Rule 14a-8 under the Securities Exchange Act of 1934 ("Rule 14a-8") must deliver the proposal to our principal executive offices no later than the close of business on March 20, 2017. We have determined March 20, 2017 to be a reasonable time before we begin to print and mail our proxy materials. Submissions should be addressed to Corporate Secretary, Extraction Oil & Gas, Inc., 370 17th Street, Suite 5300, Denver, Colorado 80202, and should comply with the requirements of Rule 14a-8. The date of our 2017 Annual Meeting is May 4, 2017.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2017 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2016, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2017 Proxy Statement"), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2017 Proxy Statement is incorporated herein by reference.

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

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2017 Proxy Statement is incorporated herein by reference.

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

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2017 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2017 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

2. FINANCIAL STATEMENT SCHEDULES

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

3. EXHIBITS

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below in the "Index to Exhibits" attached hereto and are incorporated herein by reference.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements 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.

Date: March 13, 2017.

Extraction Oil & Gas, Inc.

By: /s/ MARK A. ERICKSON
Mark A. Erickson
Chairman and Chief Executive Officer
(Principal Executive Officer)

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

/s/ RUSSELL T. KELLEY, JR. Russell T. Kelley, Jr.	Chief Financial Officer (Principal Financial Officer)	March 13, 2017
/s/ TOM L. BROCK Tom L. Brock	Vice President, Chief Accounting Officer (Principal Accounting Officer)	March 13, 2017
/s/ MATTHEW R. OWENS Matthew R. Owens	President and Director	March 13, 2017
/s/ JOHN S. GAENSBAUER John S. Gaensbauer	Director	March 13, 2017
/s/ PETER A. LEIDEL Peter A. Leidel	Director	March 13, 2017
/s/ MARVIN M. CHRONISTER Marvin M. Chronister	Director	March 13, 2017
/s/ PATRICK D. O'BRIEN Patrick D. O'Brien	Director	March 13, 2017
/s/ WAYNE W. MURDY Wayne W. Murdy	Director	March 13, 2017
/s/ DONALD L. EVANS Donald L. Evans	Director	March 13, 2017

INDEX TO EXHIBITS

Exhibit Number	Description
**2.1	Agreement and Plan of Merger, dated October 17, 2016, by and between Extraction Oil & Gas, Inc. and Extraction Oil & Gas Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**4.1	Amended and Restated Registration Rights Agreement, dated October 17, 2016, by and among Extraction Oil & Gas, Inc. and the other persons named therein (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.2	Registration Rights Agreement, dated October 3, 2016, by and among Extraction Oil & Gas, LLC, Extraction Oil & Gas Holdings, LLC and the other persons named therein (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.3	Indenture, dated July 18, 2016, by and among Extraction Oil & Gas Holdings, LLC, Extraction Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-1/A (File No. 333-213634) filed with the Commission on September 26, 2016).
**4.4	Supplemental Indenture, dated October 17, 2016, by and among Extraction Oil & Gas, Inc., Extraction Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.5	Registration Rights Agreement, dated December 15, 2016, by and among Extraction Oil & Gas, Inc. and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on December 16, 2016).
†**10.1	Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.2	Form of Restricted Stock Unit Award Agreement (for Employees) (incorporated by reference to Exhibit 4.5 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).

Exhibit Number	Description
†**10.3	Form of Restricted Stock Unit Award Agreement (for Directors) (incorporated by reference to Exhibit 4.6 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.4	Form of Stock Option Award Agreement (incorporated by reference to Exhibit 4.7 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.5	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Mark A. Erickson (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.6	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Matthew R. Owens (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.7	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Russell T. Kelley, Jr. (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.8	Indemnification Agreement (Mark A. Erickson) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.9	Indemnification Agreement (Matthew R. Owens) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.10	Indemnification Agreement (Russell T. Kelley, Jr.) (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.11	Indemnification Agreement (John S. Gaensbauer) (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.12	Indemnification Agreement (Peter A. Leidel) (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.13	Indemnification Agreement (Marvin M. Chronister) (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.14	Indemnification Agreement (Patrick D. O'Brien) (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.15	Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 31, 2016).

Exhibit Number	Description
†**10.16	Indemnification Agreement (Tom L. Brock) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 31, 2016).
†**10.17	Amended and Restated Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on November 22, 2016).
†**10.18	Indemnification Agreement (Donald L. Evans) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File 001-37907) filed with the Commission on December 16, 2016).
†**10.19	Indemnification Agreement (Wayne W. Murdy) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File 001-37907) filed with the Commission on December 16, 2016).
**10.20	Credit Agreement, dated as of September 4, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.21	Amendment No. 1 to the Credit Agreement, dated as of September 24, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.22	Amendment No. 2 to the Credit Agreement, dated as of November 10, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.23	Amendment No. 3 to the Credit Agreement, dated as of December 30, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.24	Amendment No. 4 to the Credit Agreement, dated as of May 27, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.25	Amendment No. 5 to the Credit Agreement, dated as of September 1, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).

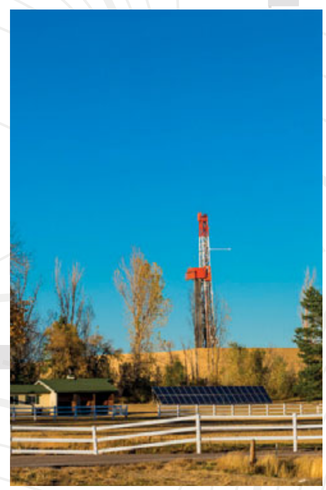
Exhibit Number	Description
**10.26	Amendment No. 6 to the Credit Agreement, dated as of September 10, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.27	Amendment No. 7 to the Credit Agreement, dated as of December 15, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.28	Amendment No. 8 to the Credit Agreement, dated as of June 13, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.29	Amendment No. 9 to the Credit Agreement, dated as of August 12, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.30	Amendment No. 10 to the Credit Agreement, dated as of September 14, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 26, 2016).
**10.31	Common Stock Subscription Agreement, dated as of December 12, 2016, by and among Extraction Oil & Gas, Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (file No. 001-37907) filed with the Commission on December 12, 2016).
*21.1	Subsidiaries of the Registrant
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Description
*99.1	Report of Ryder Scott Company, L.P.
*101	Interactive Data Files

† Management contract or compensatory plan or agreement.
* Filed herewith.
** Previously filed.

CORPORATE INFORMATION

CORPORATE INFORMATION



CORPORATE INFORMATION

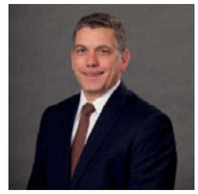
Management Team

Mark Erickson
Chief Executive Officer and Chairman of the Board

Matt Owens
President

Russell Kelley
Chief Financial Officer

Eric Jacobsen
Senior Vice President, Operations



Tom Brock
Chief Accounting Officer

Eric Christ
General Counsel and Corporate Secretary

Board of Directors

Mark Erickson
Chief Executive Officer and Chairman of the Board

Matt Owens
President

Peter Leidel
Director

Marvin Chronister
Director

John Gaensbauer
Director

Pat O'Brien
Director

Donald Evans
Director

Wayne Murdy
Director

Additional Resources

Common Stock Information
The Common Stock is traded on the NASDAQ MKT under the symbol XOG.

Transfer Agent
American Stock Transfer & Trust Company
6201 15th Avenue
Brooklyn, NY 11219
800-937-5449

Auditor
PricewaterhouseCoopers LLP

Annual Meeting
The Annual Meeting of the Stockholders is May 4, 2016, at noon CDT at The Houstonian Hotel, 111 North Post Oak Lane, Houston, TX, 77024.

Reserve Engineers
Ryder Scott, Denver, CO

Form 10-K
Additional copies of the Company's Form 10-K as filed with the Securities and Exchange Commission, are available at our website, www.extractionog.com, under Investors.

EXTRACTION
Oil & Gas

Extraction Oil & Gas Inc. • 370 17th Street • Suite 5300 • Denver, CO 80202

www.extractionog.com