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

☐ **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 001-33614

ULTRA PETROLEUM CORP.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**N/A**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. employer identification number)*
400 North Sam Houston Parkway East, Suite 1200, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip code)*

(281) 876-0120

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:
None.

Securities registered pursuant to Section 12(g) of the Act:
Common Shares, without par value

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $269,948,228 as of June 30, 2016 (based on the last reported sales price of $1.76 of such stock on the OTC on such date).

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of February 15, 2017 was 153,418,041.

Documents incorporated by reference: The definitive Proxy Statement for the 2017 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2016, is incorporated by reference in Part III of this Form 10-K.

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Certain Definitions

Terms used to describe quantities of oil and natural gas and marketing

- ***Bbl*** — One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.
- ***Bcf*** — One billion cubic feet of natural gas.
- ***Bcfe*** — One billion cubic feet of natural gas equivalent.
- ***Tcfe*** — One trillion cubic feet of natural gas equivalent.
- ***BOE*** — One barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.
- ***BTU*** — British Thermal Unit.
- ***Condensate*** — An oil-like, liquid hydrocarbon which is produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- ***MBbl*** — One thousand barrels of crude oil or other liquid hydrocarbons.
- ***Mcf*** — One thousand cubic feet of natural gas.
- ***Mcfe*** — One thousand cubic feet of natural gas equivalent, converting oil, condensate or NGLs to natural gas at the ratio of one barrel of oil, condensate or NGLs to six Mcf of natural gas.
- ***MMBbl*** — One million barrels of crude oil or other liquid hydrocarbons.
- ***MMcf*** — One million cubic feet of natural gas.
- ***MMBTU*** — One million British Thermal Units.
- ***NGL or NGLs*** — Natural gas liquids, which are expressed in barrels.

Terms used to describe the Company's interests in wells and acreage

- ***Gross oil and natural gas wells or acres*** — The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- ***Net oil and natural gas wells or acres*** — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.
- ***Prospect*** — A location where hydrocarbons such as oil and gas are believed to be present in quantities which are economically feasible to produce.

Terms used to assign a present value to the Company's reserves

- ***Standardized measure of discounted future net cash flows, after income taxes*** — The present value, discounted at 10%, of the after tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and natural gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the oil and natural gas spot prices based on the average price during the 12-month period before the ending date of the period covered by the report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for quality and transportation. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes, using rates in effect on the date of the report, are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

- ***Standardized measure of discounted future net cash flows before income taxes*** — The discounted present value of proved reserves is identical to the standardized measure described above, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different income tax rates.

Terms used to classify the Company's reserve quantities

The Securities and Exchange Commission ("SEC") definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

Economically producible — A resource that generates revenue that exceeds (or is reasonably expected to exceed) costs of the operation.

Estimated ultimate recovery ("EUR") — The sum of reserves remaining as of a given date and cumulative production as of that date.

Proved oil and gas reserves — Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of available 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 regulation — before 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.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited fluid contacts, if any,

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period before the ending date of the period covered by the report, determined as an un-weighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved developed oil and gas reserves — Proved oil and gas reserves that can be expected to be recovered:

a. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

b. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

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

Reasonable certainty — If deterministic methods are used, a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the 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.

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

Reserves — Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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

Terms used to describe the legal ownership of the Company's oil and natural gas properties

- ***Revenue interest*** — The amount of the interest owned in the proceeds derived from a producing well less all royalty interests.
- ***Working interest*** — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

- ***Seismic data*** — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- ***2-D seismic data*** — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- ***3-D seismic data*** — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Other Terms

- ***All-in costs*** — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges, depletion, depreciation and amortization, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- ***Reserve replacement ratio*** — The sum of the estimated net proved reserves added through extensions, discoveries, revisions and additions (including purchases of reserves) for a specified period of time divided by production for that same period of time.
- ***Finding and development costs*** — The sum of property acquisition costs, exploration costs and development costs for a specified period of time, divided by the total of proved reserve extensions, discoveries, revisions and additions (including purchases) for that same period of time.

PART I

Item 1. *Business.*

General

Ultra Petroleum Corp. ("Ultra" or the "Company") is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company was incorporated on November 14, 1979, under the laws of the Province of British Columbia, Canada. Ultra remains a Canadian company, but since March 2000, has operated under the laws of Yukon, Canada pursuant to Section 190 of the *Yukon Business Corporations Act*. The Company's principal business activities are developing its long-life natural gas reserves in the Green River Basin of southwest Wyoming — the Pinedale and Jonah fields, its oil reserves in the Uinta Basin in northeast Utah and its natural gas reserves in the north-central Pennsylvania area of the Appalachian Basin.

The Company's annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge to the public on the Company's website at www.ultrapetroleum.com. To access the Company's SEC filings, select "SEC Filings" under the Investors tab on the Company's website. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Director, Investor Relations, 400 N. Sam Houston Pkwy. E., Suite 1200, Houston, TX 77060, (281) 876-0120. Any materials that the Company has filed with the SEC may be read and/or copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding the Company. The SEC's website address is www.sec.gov.

Chapter 11 Proceedings

On April 29, 2016 (the "Petition Date"), to restructure their respective obligations and capital structures, the Company and each of its direct and indirect wholly owned subsidiaries (collectively, the "Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Debtors' chapter 11 cases are being jointly administered for procedural purposes under the caption In re Ultra Petroleum Corp., et al, Case No. 16-32202 (MI) (Bankr. S.D. Tex.). Information about our chapter 11 cases is available at our website (www.ultrapetroleum.com) and also at a website maintained by our claims agent, Epiq Systems (http://dm.epiq11.com/UPT/Docket).

We are currently operating our business as a debtor-in-possession in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. After we filed our chapter 11 petitions, the Bankruptcy Court granted certain relief we requested enabling us to conduct our business activities in the ordinary course, including, among other things and subject to the terms and conditions of such orders, authorizing us to pay employee wages and benefits, pay taxes and certain governmental fees and charges, continue to operate our cash management system in the ordinary course, remit funds we hold from time to time for the benefit of third parties (such as royalty owners), and pay the prepetition claims of certain of our vendors that hold liens under applicable non-bankruptcy law. For goods and services provided following the Petition Date, we intend to pay vendors in full under normal terms.

Subject to certain exceptions provided for in section 362 of the Bankruptcy Code, all judicial and administrative proceedings against us or our property were automatically enjoined, or stayed, as of the Petition Date. In addition, the filing of new judicial or administrative actions against us or our property for claims arising prior to the date on which our chapter 11 cases were filed were automatically enjoined. This prohibits, for example, our lenders or noteholders from pursuing claims for defaults under our debt agreements and our contract counterparties from pursuing claims for defaults under our contracts. Accordingly, unless the Bankruptcy Court agrees to lift the automatic stay, all of our prepetition liabilities and obligations should be settled or compromised under the Bankruptcy Code as part of our chapter 11 proceedings.

Our operations and ability to execute our business remain subject to the risks and uncertainties described in Item 1A, "Risk Factors". In addition, our assets, liabilities, including our capital structure, shareholders, officers and/or directors could change materially because of our chapter 11 cases. In addition, the description of our operations, properties and capital plans included in this Annual Report on Form 10-K may not accurately reflect our operations, properties and capital plans after we emerge from chapter 11.

Oil and Gas Properties Overview —

Principal Operating Areas

Ultra's operations in southwest Wyoming have historically focused on developing its long-life natural gas reserves in a tight gas sand trend located in the Green River Basin. The Company targets sands of the upper Cretaceous Lance Pool in the Pinedale and Jonah fields. The Lance Pool, as administered by the Wyoming Oil and Gas Conservation Commission ("WOGCC"), includes sands of the Lance formation at depths between approximately 8,000 and 12,000 feet and the Mesaverde formation at depths between approximately 12,000 and 14,000 feet. As of December 31, 2016, Ultra owned interests in approximately 105,000 gross (69,000 net) acres in Wyoming covering approximately 190 square miles.

The Company's operations in the Uinta Basin in Utah have focused on developing its oil-producing properties and undeveloped acreage covering approximately 8,000 net acres. The primary geologic target is the Eocene aged Green River formation found between subsurface depths of approximately 4,000 and 7,500 feet.

Ultra's operations in north-central Pennsylvania have focused on its position in the Devonian aged Marcellus Shale and other horizons at depths between approximately 4,500 and 8,500 feet. The Company's assets are located predominantly in Lycoming, Clinton and Centre counties. At December 31, 2016, the Company owned interests in approximately 144,000 gross (72,000 net) acres in Pennsylvania.

Mission and Strategy

Our overall strategy is as follows:

- Restructure the balance sheet through in-court process to provide financial strength and flexibility to develop existing assets and pursue new opportunities;
- Develop an additional 11 Tcfe of resource from existing, self-funding assets over the next twenty years;
- Maintain cost leadership status and continue to drive efficiencies and cost reductions through commodity price cycles while maintaining strict safety and environmental standards;
- Improve cash flow visibility by hedging up to 50% of volumes annually to manage commodity price risks and provide cash flow predictability;
- Maintain an entrepreneurial work environment to attract high-quality employees that are competitively rewarded for excellent performance

Exploration and Production

As of December 31, 2016, the Company did not include estimated proved undeveloped reserves ("PUD") with respect to any of its properties due to uncertainty regarding its ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves. The Company previously reported estimated PUD reserves in SEC filings, and, if in the future we can satisfy the reasonable certainty criteria for recording PUD reserves as prescribed under the SEC requirements, we would likely report estimated PUD reserves in future filings.

Green River Basin, Wyoming

During 2016, the Company participated in the drilling of 120 wells in Wyoming and continued to improve its drilling and completion efficiency on its operated wells. The Company's operated well costs declined from an annual average of $3.8 million per well during 2014 to $2.7 million per well average during 2016. The reduction in costs is attributable to drilling efficiencies and service cost reductions. The Company operates 86% of its production in the Pinedale field.

During 2017, the Company plans, based on the availability of capital, to continue developing its position in the Pinedale field, and will continue to target tight gas sands of the Lance Pool. All of the Company's drilling activity is conducted utilizing its extensive geological and geophysical data set. This data set is used to map potentially productive intervals, to refine areas of drilling focus, to identify areas for future extension of the Lance fairway and to identify deeper objectives that may warrant drilling.

Utah

During 2016, the Company did not drill any wells on the Uinta Basin properties. Due to decreased oil prices, the Company suspended completion operations in January 2015 and drilling operations in May 2015. With some improvement in oil prices in 2016, the Company decided to complete 12 of its Drilled But Uncompleted ("DUC") wells in Utah as Lower Green River producers. Another DUC well was completed as an injector as part of a second waterflood pilot. At December 31, 2016, the company had 9 wells drilled but not completed in inventory. Ultra is the sole operator of the properties with a 100% working interest. At the end of 2016, approximately 83% of the Company's gross acreage holdings in Utah were held by production.

During 2017, Ultra will continue to monitor oil prices and expected returns from its remaining inventory of locations in Utah. Should conditions warrant investment, the Company may resume drilling in the near term. The Company plans to continue the waterflood pilots and may expand the scope of that effort should pilot performance and oil price conditions show additional improvement.

Pennsylvania

During 2016, the Company did not drill any wells on its Pennsylvania properties. At the end of 2016, approximately 99% of the Company's gross acreage holdings in Pennsylvania were held by production. During 2017, the Company does not plan to drill any wells in Pennsylvania.

Marketing and Pricing

Overview

Ultra derives its revenues from the sale of its natural gas and associated condensate produced from wells operated by the Company in the Green River Basin in southwest Wyoming, from the sale of natural gas produced from wells operated by others in the Appalachian Basin in Pennsylvania and from the sale of crude oil and natural gas from wells operated by the Company in the Uinta Basin of Utah. During 2016, 94% of the Company's production and 85% of its revenues were attributable to natural gas, with the balance attributable to associated condensate and crude oil.

The Company's natural gas revenues are determined by prevailing natural gas market prices in the Rocky Mountain region of the United States, specifically, southwest Wyoming, and by natural gas market prices in the Eastern region of the United States. The Company's oil revenues are determined by prevailing oil and condensate prices in the Rocky Mountain region of the United States.

Natural Gas Marketing

Ultra currently sells all of its natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations and prices (daily, monthly and longer term). The Company's customer base includes a significant number of customers situated in the various regions of the United States. The sale of the Company's natural gas is "as produced". As such, the Company does not maintain any significant inventories or imbalances of natural gas.

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with several midstream service providers that gather, compress and process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah fields. Recently, the Company was able to renegotiate its processing contracts with processors of a majority of the Company's production in Wyoming. Under these agreements, the midstream service providers continue to expand their facilities' capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. The Company believes that the capacity of the midstream infrastructure related to its production will continue to be adequate to allow it to sell essentially all of its available natural gas production.

In Pennsylvania, the Company and its partners have constructed gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from the Company's producing natural gas wells. These facilities are gathering systems and related infrastructure, and their construction is expected to continue, to some extent, until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that treating facilities of this type will not be required in the future to accommodate the Company's Pennsylvania production.

Basis differentials. The market price for natural gas is influenced by a number of regional and national factors which are beyond the Company's ability to control. These factors include, among others, weather, natural gas supplies, imports from Canada, natural gas demand, inventory levels in natural gas storage fields, and natural gas pipeline capacity to export gas from the basins where the Company's production is located. See Item 1A — Risk Factors for more information about risks to our financial condition and business results associated with basis differentials.

The Rocky Mountain region is a net exporter of natural gas because local natural gas production exceeds local demand, especially during non-winter months. As a result, natural gas production in southwest Wyoming has from time to time sold at a discount relative to other U.S. natural gas production sources or market areas. These regional pricing differentials, or discounts, are typically referred to as "basis" or "basis differentials" and are reflective, to some extent, of i.) the costs associated with transporting the Company's gas to markets in other regions or states, and ii.) the availability of pipeline capacity to move the Company's gas to market.

The Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains is the price that is reflective of the Company's gas sold in the Opal, Wyoming area and the Inside FERC First of Month Index for Dominion Transmission Inc — Appalachia is the price that is reflective of the Company's gas sold in Pennsylvania

Basis differentials in southwest Wyoming remain strong by historical measurement. From 1990 to 2009 the average annual basis for Northwest Pipeline — Rocky Mountains averaged 22.7% below Henry Hub. After Rockies Express Pipeline began flowing on an annualized basis in 2010 which was followed by Ruby Pipeline which began flowing in 2011, the average annual basis for Northwest Pipeline — Rocky Mountains averaged 5.6% below Henry Hub. The additional capacity of these two pipelines has had a significant positive impact on the value that the Company receives for its natural gas production in southwest Wyoming.

The table below provides a historical and future perspective on average annual basis differentials for Wyoming natural gas (NW Rockies) and historically premium markets in the Northeast (Appalachia). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's M2M (Mark to Market) Report and Bloomberg on December 31, 2016.

	2013	2014	2015	2016	2017	2018	2019
NW Pipeline Corp. — Rocky Mountains	96%	96%	93%	91%	93%	91%	90%
Dominion Transmission Inc — Appalachia	94%	74%	54%	56%	67%	71%	76%

Oil Marketing

Wyoming. The Company markets its Wyoming condensate to various purchasers, which are primarily refiners in the Salt Lake City, Utah area. The Company's condensate realized pricing is typically based on New York Mercantile Exchange crude futures daily settlement prices, less a negotiated location/transportation discount or differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid for on a monthly basis. The Company routinely maintains only operating inventories of condensate production and sells its product on an "as produced" basis. A portion of the Company's condensate sales are entered into by its operating partners in the Pinedale field.

Utah. The Company's properties in the Uinta Basin produce what is typically referred to as Black Wax Crude which is considered a medium grade of crude oil. This oil is marketed through short-term or long-term contracts with refiners in the Salt Lake City, Utah area. The price for the Company's crude oil production is typically based off of NYMEX pricing for West Texas Intermediate Crude Oil or from a posting for Black Wax Crude in the Uinta Basin, less a negotiated location/transportation discount or differential.

Derivatives

The Company, from time to time and in the regular course of its business, hedges a portion of its natural gas and crude oil production primarily through the use of financial swaps with creditworthy financial counterparties (See Note 12), or through the use of fixed price, forward sales of physical product. The Company may elect to hedge additional portions of its forecasted natural gas or crude oil production in the future, in much the same manner as it has done previously. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The Company's hedging policy limits the volumes hedged to not more than 50% of its forecast production without Board approval. During 2016, the Company did not have any open hedge positions. During 2015 and 2014, the quantities that the Company hedged for the succeeding twelve month periods represented 62% and 51%, respectively, of the Company's forecasted production for such periods. Where the Company hedged more than 50% of its forecast production, Ultra's board approved hedges of greater than 50% of the Company's forecast production for each respective period. (See Note 7 for additional information).

Significant Counterparties

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2016, the Company had one single counterparty that represented 10% or more of the Company's total revenues.

The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to the sale of natural gas and condensate as well as commodity derivatives. A more complete description of the Company's credit policies are described in Note 12. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2016.

Regulatory Matters

The Company's oil and gas operations are subject to a number of regulations. Governing agencies may include one or more of the following levels: Federal, Regional, State, County, Municipality, Tribal or other public entities. In general, the purposes of these regulations are to prevent waste of oil and natural gas resources, protect the rights of surface and mineral owners, regulate interstate transportation of oil and gas, and to govern environmental quality. Common forms of regulations may include:

- Notification to stakeholders of proposed and ongoing operations;
- Nondiscrimination statutes;
- Royalty and related valuation requirements;
- On-site security and bonding requirements;
- Location and density of drilling;
- Method of drilling, completing and operating wells;
- Measurement and reporting of oil and gas;
- Rates, terms and conditions applicable to the interstate transportation of oil and gas;
- Production, severance and ad valorem taxes;
- Management of produced water and waste;
- Surface use, reclamation and plugging and abandonment of wells.

A significant portion of the Company's operations are located on federal lands in the Pinedale and Jonah Fields of Sublette County, Wyoming. The development activities in these fields are subject to the regulation of the U.S. Bureau of Land Management ("BLM") which is responsible for governing their surface and mineral rights and regulating certain development activities in these fields. As required under the National Environmental Policy Act ("NEPA"), an Environmental Impact Statement ("EIS") was prepared to quantify and address potential impacts of natural gas development in both the Pinedale and Jonah fields. In March 2006, the BLM issued its Record of Decision ("ROD") which provides broad authorization for the development activities currently occurring in the Jonah Area. In September 2008, the BLM issued its ROD that currently governs the development activities in the Pinedale Area. In addition to the overarching authorizations provided by the Jonah and Pinedale RODs, BLM issues site-specific authorizations such as rights of way and permits to drill on an ongoing basis.

The Pinedale ROD includes some significant components to ensure the orderly and responsible development of natural gas concurrent to minimizing the environmental impact. Some of these components include:

- Year-round operations on multi-wells pads;
- Liquid gathering systems to reduce truck traffic and minimize impacts to air quality and wildlife;
- Monitoring of key wildlife species and mitigation of monitored impacts;
- Advanced emission reductions including best practices such as controlled drill rigs;
- Spatial progression of development to address specific surface and wildlife issues;
- Annual meeting and long range planning requirements to allow for socioeconomic predictability;
- Adaptive Management to consider current and changing conditions and facilitate common-sense solutions;
- Suspension of flank acreage until core acreage is developed and returned to a functioning habitat.

While the majority of the Company's operations in Wyoming are covered by the Pinedale ROD, provisions of the Jonah ROD similarly ensure responsible and orderly development of the Jonah field while minimizing the environmental impact:

- Annual reporting and long range planning requirements to allow for planned mitigation and socioeconomic predictability;
- Emission reduction report to ensure air quality goals are met;
- Annual water well monitoring reports;
- Flareless-completion technology to reduce noise, visual impacts and air emissions.

The State of Wyoming maintains governance over some of the more traditional state-regulated matters such as individual well drilling permits, spacing and pooling, wellbore construction, as well as its own regulations on safety and environmental matters. The Wyoming Oil and Gas Conservation Commission ("WOGCC") has authorized drilling density up to 1 well per 5 acres in the Pinedale field and up to 1 well per 10 acres in the Jonah field.

Regulations are well documented and the Company believes that it is substantially in compliance with current applicable laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company. However, changes to certain existing regulations are beyond the control of the Company and could introduce uncertainty and additional costs. Please see Section 1A: Risk Factors for additional information.

Mineral Leasing Act

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and gas leases by a foreign citizen or a foreign corporation except through stock ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or corporations of the United States. If these restrictions are violated, the oil and gas lease can be canceled in a proceeding instituted by the United States Attorney General. The Company qualifies as a corporation formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of the Company's equity interests may be citizens of foreign countries that are determined to be non-reciprocal countries under the Mineral Act. In such event, the federal onshore oil and gas leases held by the Company could be subject to cancellation based on such determination.

Environmental and Occupational Safety and Health Matters

Surface Damage Acts

Several states, including Wyoming, and some tribal nations have enacted surface damage statutes. These laws are designed to compensate for damages caused by oil and gas development operations. Most surface damage statutes contain entry and negotiation requirements to facilitate contact between the operator and surface owners. Most also contain binding requirements for payments by the operator in connection with development operations. Costs and delays associated with surface damage statutes could impair operational effectiveness and increase development costs.

Environmental Regulations

General. The Company's exploration, drilling and production activities from wells and oil and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products are subject to numerous stringent federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. The U.S. Environmental Protection Agency ("EPA") has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2017-2019 and as a general matter, the oil and gas exploration and production industry has been and continues to be the subject of increasing scrutiny and regulation by environmental authorities.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot be sure 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. However, it is anticipated that, absent the occurrence of an extraordinary event, compliance with these laws and regulations will not have a material effect upon the Company's operations, capital expenditures, earnings or competitive position.

Solid and Hazardous Waste. The Company has previously owned or leased and currently owns or leases, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although the Company utilized standard operating and disposal practices, hydrocarbons or other solid wastes may have been disposed of or released on or under such properties or on or under locations where such wastes have been taken for disposal. In addition, many of these properties are or have been operated by third parties over whom the Company has no control, nor has ever had control as to such entities' treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under current and evolving law, it is possible the Company could be required to remediate property, including ground water, impacted by operations of the Company or by such third party operators, or impacted by previously disposed wastes including performing remedial plugging operations to prevent future, or mitigate existing contamination.

Although oil and gas wastes generally are exempt from regulation as hazardous wastes ("Hazardous Wastes") under the federal Resource Conservation and Recovery Act ("RCRA") and some comparable state statutes, it is possible some wastes the Company generates presently or in the future may be subject to regulation under RCRA and state analogs. The EPA and various state agencies have limited the disposal options for certain wastes, including Hazardous Wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that seeks to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. Furthermore, certain wastes generated by the Company's oil and natural gas operations that are currently exempt from designation as Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials ("NORM") may affect our operations. For example, the Pennsylvania Department of Environmental Protection has asked operators to identify technologically enhanced NORM ("TENORM") in their processes, such as hydraulic fracturing sand. Local landfills only accept such waste when it meets their TENORM permit standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste, potentially increasing our disposal costs.

Hydraulic Fracturing. Many of the Company's exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Hydraulic fracturing activities are typically regulated by state oil and gas commissions. The EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the federal Safe Drinking Water Act ("SDWA") involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Congress has periodically considered legislation to amend the SDWA to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing (except where diesel is a component of the fracturing fluid) and to require the disclosure and reporting of the chemicals used in hydraulic fracturing. This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, the EPA has issued guidance regarding federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, in December 2016 EPA released its final report on a wide ranging study on the effects of hydraulic fracturing resources. While no widespread impacts from hydraulic fracturing were found, EPA identified a number of activities and factors that may have increased risk for future impacts. This study and the EPA's enforcement initiative for the energy extraction sector could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In addition, some states, including Wyoming, Pennsylvania, Utah, and Colorado, have adopted, and other states are considering adopting, regulations that require disclosure of the chemicals in the fluids used in hydraulic fracturing or well stimulation operations. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding permitting, casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. For example, the Pennsylvania Supreme Court has limited the state's ability to limit such ordinances at and strengthened the ability of municipalities to enact local ordinances regulating drilling activities. Although none of the Company's properties are in jurisdictions where the moratoria have been imposed, it is possible the jurisdictions where the Company's properties are located may adopt such limits or other limits on hydraulic fracturing in the future. The BLM finalized regulations for hydraulic fracturing activities on federal lands in March 2015, though a preliminary injunction was issued in June 2015 prior to implementation. In June 2016, a U.S. District Court judge ruled that the BLM has no authority to regulate hydraulic fracturing. ugh a Federal District Court . Further, the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater generated by hydraulic fracturing.

Superfund. Under the federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, liability, generally, is joint and several for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRP"), include current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to releases and threats of releases to protect the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, adulterated petroleum products containing other Hazardous Substances have been treated as Hazardous Substances in the past, and the Company has generated and will generate wastes that fall within CERCLA's definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. Many states have comparable laws imposing liability on similar classes of persons for releases, including for releases of materials that may not be included in CERCLA's definition of Hazardous Substances. To its knowledge, the Company has not been named a PRP under CERCLA (or any comparable state law) nor have any prior owners or operators of its properties been named as PRPs related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an Environmental Assessment ("EA") or an environmental impact statement (EIS). In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the proposed action and of such alternatives. Actions of the Company, such as drilling on federal lands, to the extent the drilling requires federal approval, may trigger the requirements of the National Environmental Policy Act, including the requirement that an EA or EIS be prepared. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations on the Company's activities, including but not limited to the restricting or prohibiting of drilling.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the Clean Water Act ("CWA"), imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and for a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company could be liable for costs and damages.

Clean Air Act. The Clean Air Act ("CAA)" regulates emissions of pollutants from stationary and mobile sources and establishes National Ambient Air Quality Standards ("NAAQS") for pollutants of concern. The CAA directs states to develop state implementation plans to achieve these standards and gives the primary role of enforcing this plans to the states. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent, technical controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

The New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs under the Clean Air Act ("CAA") impose specific requirements under both programs for compressors, controllers, dehydrators, storage tanks, natural gas processing plants, completions and certain other equipment. Periodic review and revision of these rules by federal and state agencies may require changes to our operations, including possible installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

In May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector. The EPA announced in March 2016 that it also intends to reduce methane emissions for existing sources, with a proposed rule expected in 2017. In November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. Several states, including Colorado and Pennsylvania, are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. The EPA has also adopted new rules under the CAA that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant.

Clean Water Act. The Clean Water Act (“CWA”) and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit. In addition, the EPA and the Army Corps of Engineers (“Corps”) released a rule to revise the definition of “waters of the United States” (“WOTUS”) for all Clean Water Act programs, which went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the WOTUS rule nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies’ prior regulations defining the term “waters of the United States.” Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. The WOTUS rule could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements.

Also, in August 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works, permitting several years until compliance will be enforced. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Endangered Species Act. The Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to that act, 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 migratory birds under the Migratory Bird Treaty Act, and special protections are provided to bald and golden eagles under the Bald and Golden Eagle Protection Act. The Company conducts operations on federal and other oil and natural gas leases that have species, such as raptors, that are listed and species, such as sage grouse, that could be listed as threatened or endangered under the ESA. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues its six-year effort to make listing decisions and critical habitat designations where necessary for over 250 species before the end of the agency’s 2017 fiscal year, as required under a 2011 settlement approved by the U.S. District Court for the

District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. A small portion of the lands operated by the Company in Utah have been designated on behalf of the hookless cactus, but the Company does not expect this designation to interfere with development of the properties. If the Company were to have other portions of its leases designated as critical or suitable habitat for the hookless cactus or any other protected species, it may adversely impact the value of the affected leases.

Climate Change Legislation. More stringent laws and regulations relating to climate change and greenhouse gases (“GHGs”), including methane and carbon dioxide, may be adopted and could cause the Company to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA has established GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Ultra has submitted all required annual reports to date. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

The EPA has also adopted regulations that seek to reduce GHG emissions. For example, in August 2015, the EPA issued its final Clean Power Plan rules, which seek to reduce carbon dioxide emissions from power plants by 32 percent from 2005 levels by 2030; however, on February 9, 2016, the U.S. Supreme Court stayed the implementation of the plan while it is being challenged in court. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions.

In addition to possible federal regulation, the U.S. is a party to the Paris Agreement adopted in December 2015, which aims to reduce global greenhouse emissions. Further, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These or other potential federal and state initiatives may result in so-called cap-and-trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in the Company incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. These regulatory initiatives also could adversely affect the marketability of the oil and natural gas the Company produces.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by our customers or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Worker Safety. The Occupational Safety and Health Act (“OSHA”) and analogous state laws regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

The Company believes that it is in substantial compliance with current applicable environmental and occupational health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Employees

As of December 31, 2016, the Company had 166 full-time employees, including officers.

Item 1A. ***Risk Factors.***

We have filed voluntary petitions for relief under the Bankruptcy Code and are subject to the risks and uncertainties associated with bankruptcy cases.

We have filed voluntary petitions for relief under chapter 11 of the Bankruptcy Code. For the duration of the chapter 11 cases, our business and operations will be subject to various risks, including but not limited to the following:

- our ability to develop, file and complete a chapter 11 plan of reorganization, particularly during the exclusivity period (i.e. in general, the period in which we have the exclusive right to file a chapter 11 plan of reorganization);
- our ability to obtain Bankruptcy Court, creditor and regulatory approval of a chapter 11 plan of reorganization in a timely manner;
- our ability to obtain Bankruptcy Court approval with respect to motions in the chapter 11 cases and the outcomes of Bankruptcy Court rulings and of the chapter 11 cases in general;
- risks associated with third party motions in the chapter 11 cases, which may interfere with our business operations or our ability to propose and/or complete a chapter 11 plan of reorganization;
- increased costs related to the chapter 11 cases and related litigation;
- a loss of, or a disruption in the materials or services received from, suppliers, contractors or service providers with whom we have commercial relationships;
- potential increased difficulty in retaining and motivating our key employees through the process of reorganization, and potential increased difficulty in attracting new employees; and
- significant time and effort required to be spent by our senior management in dealing with the bankruptcy and restructuring activities rather than focusing exclusively on business operations.

We are also subject to risks and uncertainties with respect to the actions and decisions of creditors and other third parties who have interests in our chapter 11 cases that may be inconsistent with our plans. These risks and uncertainties could affect our business and operations in various ways and may significantly increase the duration of the chapter 11 cases. Because of the risks and uncertainties associated with chapter 11 cases, we cannot predict or quantify the ultimate impact that events occurring during the chapter 11 cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we predict the ultimate impact that events occurring during the chapter 11 cases may have on our corporate or capital structure.

We can make no assurance that there will be any recovery available to investors holding the shares of our existing common stock after the conclusion of our chapter 11 proceedings.

We have a significant amount of indebtedness that is senior to our existing common stock in our capital structure. As a result, the value attributable to shares of our existing common stock will be impacted, possibly materially, by the reorganization of our capital structure through our chapter 11 proceedings. We can make no assurance that there will be any recovery available to investors holding the shares of our existing common stock after the conclusion of our chapter 11 proceedings. Any trading in shares of our common stock during the pendency of the chapter 11 proceedings is highly speculative and poses substantial risks to purchasers of shares of our common stock.

Operating under Bankruptcy Court protection for a long period of time may harm our business.

Our future results are dependent upon the successful confirmation and implementation of a plan of reorganization. A long period of operations under Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as the proceedings related to the chapter 11 proceedings continue, our senior management will be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. A prolonged period of operating under Bankruptcy Court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer the proceedings related to the chapter 11 proceedings continue, the more likely it is that our customers and suppliers will lose confidence in our ability to reorganize our businesses successfully and seek to establish alternative commercial relationships.

In addition, so long as the chapter 11 proceedings continue, we will be required to incur substantial costs for professional fees and other expenses associated with the administration of the chapter 11 proceeding. The chapter 11 cases may also require us to seek debtor-in-possession financing to fund operations, although we do not plan to obtain debtor-in-possession financing at this time. If we are required to seek but are unable to obtain such financing on favorable terms or at all, our chances of successfully reorganizing our business may be seriously jeopardized, the likelihood that we instead will be required to liquidate our assets may be enhanced, and, as a result, any securities in the debtor could become further devalued or become worthless.

Furthermore, we cannot predict the ultimate amount of all settlement terms for the liabilities that will be subject to a plan of reorganization. Even once a plan of reorganization is approved and implemented, our operating results may be adversely affected by the possible reluctance of prospective lenders and other counterparties to do business with a company that recently emerged from chapter 11 proceedings.

We may not be able to obtain confirmation of a chapter 11 plan of reorganization.

To emerge successfully from Bankruptcy Court protection as a viable entity, we must meet certain statutory requirements with respect to adequacy of disclosure with respect to a chapter 11 plan of reorganization (“Plan”), solicit and obtain the requisite acceptances of such a plan and fulfill other statutory conditions for confirmation of such a plan, which have not occurred to date. The confirmation process is subject to numerous, unanticipated potential delays, including a delay in the Bankruptcy Court’s commencement of the confirmation hearing regarding our plan.

We may not receive the requisite acceptances of constituencies in the proceedings related to the chapter 11 proceedings to confirm our Plan. Even if the requisite acceptances of our Plan are received, the Bankruptcy Court may not confirm such a plan. The precise requirements and evidentiary showing for confirming a plan, notwithstanding its rejection by one or more impaired classes of claims or equity interests, depends upon a number of factors including, without limitation, the status and seniority of the claims or equity interests in the rejecting class (i.e., secured claims or unsecured claims, subordinated or senior claims, preferred or common stock).

If a chapter 11 plan of reorganization is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if anything, holders of claims against us would ultimately receive with respect to their claims.

Even if a chapter 11 plan of reorganization is consummated, we will continue to face risks.

Even if a chapter 11 plan of reorganization is consummated, we will continue to face a number of risks, including certain risks that are beyond our control, such as further deterioration or other changes in economic conditions, changes in our industry, potential revaluing of our assets due to chapter 11 proceedings, changes in consumer demand for, and acceptance of, our oil and gas and increasing expenses. Some of these concerns and effects typically become more acute when a case under the Bankruptcy Code continues for a protracted period without indication of how or when the case may be completed. As a result of these risks and others, there is no guaranty that the Plan or any other plan of reorganization will achieve our stated goals.

In addition, at the outset of the chapter 11 proceedings, the Bankruptcy Code gives the debtor the exclusive right to file and solicit acceptance of the Plan and prohibits creditors, equity security holders and others from filing or soliciting a plan for a certain period of time. To date, we have retained the exclusive right to propose the Plan and solicit acceptances thereof. If the Bankruptcy Court terminates that right, however, or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of the Plan in order to achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of the chapter 11 process. Adequate funds may not be available when needed or may not be available on favorable terms.

Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. In addition to the cash requirements necessary to fund ongoing operations, we have incurred significant professional fees and other costs in connection with preparation for the chapter 11 proceedings and expect that we will continue to incur significant professional fees and costs throughout our chapter 11 proceedings. We cannot assure you that cash on hand and cash flow from operations will be sufficient to continue to fund our operations and allow us to satisfy our obligations related to the chapter 11 proceedings until we are able to emerge from our chapter 11 proceedings.

Our liquidity, including our ability to meet our ongoing operational obligations, is dependent upon, among other things: (i) our ability to comply with the terms and conditions of any cash collateral order that may be entered by the Bankruptcy Court in connection with the chapter 11 proceedings, (ii) our ability to maintain adequate cash on hand, (iii) our ability to generate cash flow from operations, (iv) our ability to develop, confirm and consummate a chapter 11 plan or other alternative restructuring transaction, and (v) the cost, duration and outcome of the chapter 11 proceedings.

In certain instances, a chapter 11 case may be converted to a case under chapter 7 of the Bankruptcy Code.

Upon a showing of cause, the Bankruptcy Court may convert our chapter 11 case to a case under chapter 7 of the Bankruptcy Code. In such event, a chapter 7 trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the Bankruptcy Code. We believe that liquidation under chapter 7 would result in significantly smaller distributions being made to our creditors than those provided for in our Plan because of (i) the likelihood that the assets would have to be sold or otherwise disposed of in a distressed fashion over a short period of time rather than in a controlled manner and as a going concern, (ii) additional administrative expenses involved in the appointment of a chapter 7 trustee, and (iii) additional expenses and claims, some of which would be entitled to priority, that would be generated during the liquidation and from the rejection of leases and other executory contracts in connection with a cessation of operations.

As a result of the chapter 11 cases, our historical financial information may be volatile and not be indicative of our future financial performance.

During the chapter 11 proceedings, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments and may significantly impact our consolidated financial statements. As a result, our historical financial performance may not be indicative of our future financial performance.

Our capital structure will likely be significantly altered under any chapter 11 plan confirmed by the Bankruptcy Court. Under fresh-start accounting rules that may apply to us upon the effective date of a chapter 11 plan, our assets and liabilities would be adjusted to fair value, which could have a significant impact on our financial statements. Accordingly, if fresh-start accounting rules apply, our financial condition and results of operations following our emergence from chapter 11 would not be comparable to the financial condition and results of operations reflected in our historical financial statements. In connection with the chapter 11 cases and the development of a chapter 11 plan, it is also possible that additional restructuring and related charges may be identified and recorded in future periods. Such charges could be material to our consolidated financial position, liquidity and results of operations.

We may be subject to claims that will not be discharged in the chapter 11 proceedings, which could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Court provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation. With few exceptions, all claims that arose prior to April 29, 2016 or before confirmation of the plan of reorganization (i) would be subject to compromise and/or treatment under the plan of reorganization and/or (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization. Any claims not ultimately discharged through a plan of reorganization could be asserted against the reorganized entities and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

Transfers of our equity, or issuances of equity in connection with our chapter 11 proceedings, may impair our ability to utilize our federal income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have U.S. federal net operating loss carryforwards of approximately $1.2 billion as of December 31, 2016. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability is subject to certain requirements and restrictions. If we experience an "ownership change," as defined in section 382 of the U.S. Internal Revenue Code, then our ability to use our net operating loss carryforwards may be substantially limited, which could have a negative impact on our financial position and results of operations. Generally, there is an "ownership change" if one or more shareholders owning 5% or more of a corporation's common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. Following the implementation of a plan of reorganization, it is possible that an "ownership change" may be deemed to occur. Under section 382 of the U.S. Internal Revenue Code, absent an application exception, if a corporation undergoes an "ownership change," the amount of its net operating losses that may be utilized to offset future taxable income generally is subject to an annual limitation on the amount of federal income tax net operating loss carry-forwards existing prior to the change that it could utilize to offset its taxable income in any future taxable year to an amount generally equal to the value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. Because the value of our stock can fluctuate materially, it is possible an ownership change would materially limit our ability to utilize our substantial federal income tax net operating loss carry-forwards in the future. There can be no assurance that we will be able to utilize our federal income tax net operating loss carry-forwards to offset future taxable income.

We may experience increased levels of employee attrition as a result of the chapter 11 cases.

As a result of the chapter 11 cases, we may experience increased levels of employee attrition, and our employees likely will face considerable distraction and uncertainty. A loss of key personnel or material erosion of employee morale could adversely affect our business and results of operations. Our ability to engage, motivate and retain key employees or take other measures intended to motivate and incent key employees to remain with us through the pendency of the chapter 11 cases is limited by restrictions on implementation of incentive programs under the Bankruptcy Code. The loss of services of members of our senior management team could impair our ability to execute our strategy and implement operational initiatives, which would be likely to have a material adverse effect on our financial condition, liquidity and results of operations.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our historical business strategy.

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our historical business strategy, we may be required to curtail operations, which could adversely affect our financial condition and results of operations.

Our operations could be adversely affected if we fail to maintain required bonds.

Federal and state laws require bonds or cash deposits to secure our obligations with respect to various parts of our operations. Our failure to maintain, or inability to acquire, bonds that are required by state and federal law would have a material adverse effect on us. That failure could result from a variety of factors including: (i) our failure to comply with rules and regulations of Federal and state governmental agencies, including the United States Bureau of Land Management, (ii) the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; (iii) and the exercise by third-party bond issuers of their right to refuse to renew the bonds. If we fail to maintain required bonds, our production may significantly decrease, which would significantly decrease our already constrained cash flow.

We cannot control the future price of oil and natural gas and sustained periods of low prices could hurt our profitability and financial condition and could impair our ability to grow our business or to perform the obligations in our agreements, including the agreements governing our indebtedness.

Sustained periods of low commodity prices will adversely affect our operations and financial condition. Our revenues, profitability, liquidity, ability to raise capital for our business, future growth, ability to operate, develop and explore our properties, and the carrying value of our properties depend heavily on prevailing prices for oil and natural gas.

Natural gas comprised approximately 94% of our total production for the year ended December 31, 2016 and represented 92% of our total proved reserves as of December 31, 2016. Historically, natural gas prices have been highly volatile, including in the Rocky Mountain region of the United States where the vast majority of our natural gas is produced. Prices have been affected by actions of federal, state and local governments and agencies, foreign governments, national and international economic and political conditions, levels of consumer demand, weather conditions, domestic and foreign supply of oil and natural gas, proximity and capacity of gas pipelines and other transportation facilities, the price and availability of equipment, materials and personnel to conduct operations, and the price and availability of alternative fuels. These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of natural gas. Any substantial or extended decline in the price of natural gas will have a material adverse effect on our financial condition and results of operations, including reduced cash flow and borrowing capacity, and lower proved reserves. Price volatility also makes it difficult to budget for and project the return on potential acquisitions and development and exploration projects, and sustained lower gas prices have caused and may, in the future continue to cause, us or the operators of properties in which we have ownership interests to curtail projects and limit or suspend drilling, completion or even production activities.

Crude oil comprised approximately 6% of our total production for the year ended December 31, 2016 and represented 5% of our total proved reserves as of December 31, 2016. Crude oil prices declined substantially from late 2014 through early 2016 and have remained low during the first months of 2017 despite a modest recovery. In the future, crude oil prices may remain at current levels or fall to lower levels. If crude oil prices remain at current levels or fall to lower levels, this will adversely affect our crude oil operations and our financial condition. Most of the production from our Uinta Basin properties is crude oil. At current oil prices, it is not profitable for us to drill and complete new wells on our Uinta Basin properties.

In addition, because we are significantly leveraged, a substantial decrease in our revenue due to low commodity prices is currently impairing and may in the future continue to impair our ability to satisfy payment obligations on our indebtedness and reduce funds available for operations and future business opportunities.

A substantial or extended decline in oil and natural gas 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 price we receive for our oil and natural gas heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. The spot natural gas prices during 2016 ranged from a high of $3.99 to a low of $1.61 per MMBtu and the spot oil prices during 2016 ranged from a high of $54.51 to a low of $26.05 per Bbl. Thus far in 2017, commodity prices have continued to be depressed and volatile, with spot natural gas prices ranging from a high of $3.57 to a low of $2.89 per MMBtu and the spot oil prices ranging from a high of $55.24 to a low of $50.71 per Bbl through February 15, 2017. These markets 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 and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is currently sold at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. Lower oil and natural gas prices will reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our identified drilling locations, and, may cause us to make significant downward adjustments to our estimated proved reserves or to be unable to claim proved undeveloped reserves at all. If oil and natural gas prices remain at current levels or experience a substantial or extended decline from current levels, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures will be materially and adversely affected.

Our reserve estimates may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil, natural gas and NGLs that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, the timing and identification of future drilling locations, commodity prices, future production levels, costs and the ability to finance future development that may not prove correct over time. Predictions of future production levels, development schedules (particularly with regard to non-operated properties), commodity prices and future operating costs are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

The present value of net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for quality and transportation fees. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate. Actual current and future commodity prices and costs may be materially higher or lower, and higher future costs and/or lower future commodity prices may impact whether development of our reserves in the future occurs as scheduled or at all. In addition, the 10% discount factor, which the SEC requires us to use in calculating our discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on our cost of capital from time to time and/or the risks associated with our business.

Competitive industry conditions may negatively affect our ability to conduct operations.

We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and natural gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill and complete wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;

- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties;
- our ability to comply with administrative, regulatory and other governmental requirements; and
- our ability to access pipelines, and the locations of facilities used to produce and transport oil and natural gas production.

Factors beyond our control affect our ability to effectively market production and may ultimately affect our financial results.

The ability to market oil and natural gas depends on numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- the availability of pipeline, rail and refinery capacity, including facilities owned and operated by third parties;
- the availability of a market for our oil and natural gas production;
- the availability of satisfactory transportation arrangements for our oil and natural gas production;
- the proximity of natural gas production to natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing and transportation; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors and other factors beyond our control, we may be unable to market all of the oil and natural gas that we produce or obtain favorable prices for such production.

Any derivative transactions we enter into may limit our gains and expose us to other risks.

We may enter into financial derivative transactions from time to time to manage our exposure to commodity price risks. These transactions limit our potential gains if commodity prices rise above the levels established by our derivative transactions. These transactions may also expose us to other risks of financial losses, for example, if our production is less than we anticipated at the time we entered into a derivative instrument or if a counterparty to our derivative instruments fails to perform its obligations under a derivatives transaction.

Legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd–Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the U.S. Commodity Futures Trading Commission (the "CFTC") and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on November 5, 2013, a proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has issued a proposed rule on margin requirements for swap transactions, which proposes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or margin requirements, depending on the Company's ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require us to comply with position limits, margin requirements and with certain clearing and trade-execution requirements in connection with our financial derivative activities. The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to financial derivatives to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

Compliance with environmental and occupational safety and health laws and other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous and complex laws and regulations relating to environmental and occupational protection. These laws and regulations, which are continuously being reviewed for amendment and/or expansion, may:

- require that we acquire permits before developing our properties;
- restrict the substances that can be released into the environment in connection with drilling, completion and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations or under the common law, we could be liable for personal injury and clean-up costs and other environmental, natural resource and property damages, as well as administrative, civil and criminal penalties or injunctions. Failure to comply with these laws and regulations could also result in the occurrence of delays or restrictions in permitting or performance of projects, or the issuance of orders and injunctions limiting or preventing operations relating to our properties in some areas. Under certain environmental laws and regulations, an owner or operator of our properties could be subject to strict, joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether the owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred. Private parties, including the owners of properties upon which wells are drilled or facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination or for personal injury or property damage. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of environmental damages.

We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine emissions, greenhouse gases and hydraulic fracturing. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by Ultra or other operators of the properties to attain and maintain compliance and may otherwise have a material adverse effect on the results of operations, competitive position or financial condition of Ultra or such other operators. Increased scrutiny of the oil and natural gas industry may occur as a result of EPA's FY2017-2019 National Enforcement Initiatives, through which EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.

A significant percentage of our operations are conducted on federal and state lands. These operations are subject to a wide variety of regulations as well as other permits and authorizations which must be obtained from and issued by state and federal agencies. To conduct these operations, we may be required to file applications for permits, seek agency authorizations and comply with various other statutory and regulatory requirements. Complying with any of these requirements may adversely affect our ability to complete our drilling programs at the costs and in the time periods anticipated.

Climate change legislation or regulations restricting emissions of "greenhouse gases" ("GHGs") could result in increased operating costs and reduced demand for the oil and gas we produce.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA also requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We will continue to incur costs associated with this reporting obligation.

In May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector. The EPA announced in March 2016 that it also intends to reduce methane emissions for existing sources, with a proposed rule expected in 2017. In November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. Several states, including Colorado and Pennsylvania, are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states and regions have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall GHG emissions. The cost of these allowances could escalate significantly over time. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the international climate change agreement. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or floods, or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions; however, EPA has taken certain actions with respect to regulating hydraulic fracturing. For example, EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in May 2016 governing performance standards for the oil and natural gas industry; issued in June 2016 final effluent limitations guidelines under the CWA that waste water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant; 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 BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, the U.S. District Court of Wyoming struck down this rule in June 2016; the ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals. The BLM also issued new rules in November 2016 which seek to limit methane emissions from new and existing oil and gas operations on federal lands.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Wyoming has adopted regulations requiring producers to provide detailed information about wells they hydraulically fracture in that state. Some states have adopted or are considering adopting regulations requiring disclosure of chemicals in fluids used in hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities and adversely affect our operations and financial condition.

Changes in tax laws and regulations or in our operations may impact our effective tax rate and may adversely affect our business, financial condition and operating results.

Changes in tax laws in any of the multiple jurisdictions in which we operate could result in an unfavorable change in our effective tax rate, which could adversely affect our business, financial condition and operating results. President Trump and House Republicans have each promised comprehensive U.S. tax reform. Although we cannot predict the details or scope of such tax reform, general policy proposals from the President and Congress suggest such reform could, for instance, impose a new tax on hydrocarbon production and disallow deductions for net interest expenses, depletion, intangible drilling and development costs and U.S. production manufacturing activities. Other proposals for reform have included other items that would be beneficial for us, for instance, immediate expensing of capital costs. If tax reform is enacted that reduces or eliminates provisions of the tax laws and regulations that allow us to reduce our taxes, whether by deducting expenses or otherwise without providing offsetting benefits, any such reform could have a material adverse effect on our business, results of operations and liquidity.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While our operations and financial condition have not been materially and adversely affected by cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Unless we are able to replace reserves that we have produced, our cash flows and production will decrease over time.

Our future success depends on our ability to find, acquire, develop and produce additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We can give no assurance that we will be able to find, develop or acquire additional reserves at acceptable costs.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to develop our existing reserves and to discover new oil and gas reserves.

Our ability to continue exploration and development of our properties and to replace reserves depends upon our ability to comply with our debt covenants, renegotiate our debt agreements, raise significant additional financing, or to seek and obtain other arrangements with industry participants in lieu of raising additional financing. Any arrangements that may be entered into could be expensive to us if such arrangements can be made at all. There can be no assurance that we will be able to raise additional capital in light of factors such as our financial condition, the market demand for our securities, the general condition of financial markets for independent oil and gas companies (including the markets for debt), oil and natural gas prices and general market conditions. See Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget. Continued periods of depressed commodity prices or further commodity price decreases could have a material adverse effect on our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. There can also be no assurance that we will be able to obtain other satisfactory arrangements to allow further exploration and development of our properties if we are unable to raise additional capital.

We expect to use our cash from operations and cash on hand to fund our capital budget during 2017. See Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for information about our liquidity, available cash on hand, and the status of the Credit Agreement. We previously borrowed substantially all of the funds available to us under the Credit Agreement.

Our operations may be interrupted by severe weather or drilling restrictions.

Our operations are conducted primarily in the Rocky Mountain region of the United States. We also have properties in the north-central Pennsylvania area of the Appalachian Basin. The weather in these areas can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment. Likewise, our operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

The oil and natural gas business involves a variety of operating risks, including blowouts, fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. The occurrence of any of these events with respect to any property we own or operate (in whole or in part) could have a material adverse impact on us. We and the operators of our properties maintain insurance in accordance with customary industry practices and in amounts that management believes to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

There are risks associated with our drilling activity that could impact our results of operations.

Our oil and natural gas operations are subject to all of the risks and hazards typically associated with drilling, completion, production and transportation of, oil and natural gas. These risks include the necessity of spending large amounts of money for identification and acquisition of properties and for drilling and completion of wells. In the drilling and completing of wells, failures and losses may occur before any deposits of oil or natural gas are found and produced. The presence of unanticipated pressure or irregularities in formations, blow-outs or accidents may cause such activity to be unsuccessful, resulting in a loss of our investment in such activity and possible liabilities. If oil or natural gas is encountered, there can be no assurance that it can be produced in quantities sufficient to justify the cost of continuing such operations or that it can be marketed satisfactorily.

Our decision to drill a prospect is subject to a number of factors which may alter our drilling schedule or our plans to drill at all.

A prospect is an area in which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill our prospects depends on many factors, including but not limited to: the availability and cost of capital; receipt of additional seismic data or reprocessing of existing data; material changes in current of future expected oil or natural gas prices; the costs and availability of drilling and completion equipment; the success or failure of wells drilled in similar formations or which would use the same production facilities and equipment; changes in the estimates of costs to drill or complete wells; decisions of our joint working interest owners; and regulatory, permitting and other governmental requirements. It is possible these factors and others may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

We have limited control over activities conducted on properties we do not operate.

We own interests in properties that are operated by third parties. The success, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas that we produce.

The marketability of our oil and natural gas production will depend in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and prospects.

We may fail to fully identify problems with any properties we acquire.

We acquired a portion of our acreage position in Wyoming, Pennsylvania, and Utah through property acquisitions and acreage trades, and we may acquire additional acreage in these or other regions in the future. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify.

Our acquisitions may perform worse than we expected or prove to be worth less than what we paid because of uncertain factors and matters beyond our control. In addition, our acquisitions could expose us to potentially significant liabilities.

When we make acquisitions of oil and gas properties, we make assumptions about many uncertain factors, including estimates of recoverable reserves, expected timing of recovering acquired reserves, future commodity prices, expected development and operating costs, and other matters, many of which are beyond our control. Assumptions about uncertain factors may be wrong, and the properties we acquire may perform worse than we expect, materially and adversely affecting our operations and financial condition.

Forward-Looking Statements

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. Except for statements of historical facts, all statements included in this document, including those statements preceded by, followed by or that otherwise include the words "believe," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," or similar expressions or variations on such expressions are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

Forward-looking statements include statements regarding:

- our oil and natural gas reserve quantities, and the discounted present value of those reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- our ability to respond to low natural gas prices;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- further declines, volatility of and weakness in natural gas or oil prices;
- our ability to maintain adequate liquidity in view of current natural gas prices;
- our ability to comply with the covenants and restrictions of the agreements governing our indebtedness, or our ability to amend or replace the agreements governing our indebtedness;
- any future global economic downturn;
- general economic conditions, including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;

- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business, including those related to climate change and greenhouse gases, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and the use of water, and financial derivatives and hedging activities;
- actions of operators of our oil and natural gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Location and Characteristics

The Company owns oil and natural gas leases in Wyoming, Utah, and Pennsylvania. In Colorado, the Company owns oil and natural gas leases as well as fee oil and gas rights. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production extends the lease terms until cessation of that production. In Pennsylvania, the leases are from private individuals and companies, as well as from the Commonwealth of Pennsylvania. The leases in Utah are from private individuals and companies, the State of Utah, and the federal government with primary lease terms ranging from five to ten years until the establishment of production. In 2014, the Company sold the surface rights to its undeveloped acreage in Colorado Springs, Colorado while retaining the oil and gas rights. The Company has no immediate plans for further exploration in Colorado during 2017.

As of December 31, 2016, the Company did not include estimated proved undeveloped reserves with respect to any of its properties because of the going concern assessment that prevents the reasonable certainty of a development plan as required by the SEC. The Company previously reported estimated PUD reserves in SEC filings, and, if in the future we can satisfy the reasonable certainty criteria for recording PUD reserves as prescribed under the SEC requirements, we would likely report estimated PUD reserves in future filings.

Green River Basin, Wyoming

As of December 31, 2016, the Company owned oil and natural gas leases totaling approximately 105,000 gross (69,000 net) acres in southwest Wyoming's Green River Basin. Most of this acreage covers the Pinedale and Jonah fields. Of the total acreage position in Wyoming and as of December 31, 2016, approximately 35,000 gross (23,000 net) acres were developed, and 70,000 gross (46,000 net) acres were undeveloped. The developed portion represents 61% of the Company's total developed net acreage while the undeveloped portion represents approximately 41% of the Company's total undeveloped net acreage. The Company operates 90% of its acreage position in the Pinedale field and 86% of its production.

Lease maintenance costs in Wyoming were approximately \$0.5 million for the year ended December 31, 2016. The Company currently owns 73 leases totaling 80,000 gross (53,000 net) acres that are held by production and activities ("HBP"). The HBP acreage includes all of the Company's leases within the productive area of the Pinedale and Jonah fields.

Development Wells. During 2016, the Company did not participate in the drilling of any productive development wells on the Green River Basin properties. At year-end 2016, there were no development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth. Ultra defines "Development Wells" as wells that were drilled in the current year that were proved undeveloped locations in the prior year's reserve report. As Ultra did not report proved undeveloped reserves at December 31, 2015, fewer wells are considered "Development Wells" at December 31, 2016, than in prior annual reports.

Exploratory Wells. During 2016, the Company participated in the drilling of a total of 94 gross (68.6 net) productive exploratory wells on the Green River Basin properties. At December 31, 2016, there was 26 gross (20.1 net) additional exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end. Ultra defines "Exploratory Wells" as wells that were drilled in the current year that were not proved undeveloped locations in the prior year's reserve report. As Ultra did not report proved undeveloped reserves at December 31, 2015, more wells are considered "Exploratory Wells" at December 31, 2016 than in prior annual reports.

Seismic Activity. The Company owns 492 square miles of 3D seismic data in Wyoming which, when overlap is subtracted, covers 415 square miles. The data consists of both proprietary data and data licensed from independent seismic contractors, and provides coverage over the entire productive areas of Pinedale and Jonah fields. During 2016, the Company completed a project to merge the various data sets and reprocess the entire volume.

Uinta Basin, Utah

As of December 31, 2016, the Company owned oil and natural gas leases covering 9,000 gross (8,000 net) acres in the Uinta Basin. This acreage is located in Uintah County in the eastern portion of the Uinta Basin. As of December 31, 2016, approximately 5,000 gross (5,000 net) acres were developed, and 4,000 gross (3,000 net) acres were undeveloped. The developed portion represents 13% of the Company's total developed net acreage position while the undeveloped portion represents 3% of the Company's total undeveloped net acreage position. The Company operates 100% of the properties.

Lease maintenance costs in Utah for the year ended December 31, 2016 were approximately \$0.1 million. The Company owns approximately 7,000 gross (7,000 net) acres currently held by production or activities in Utah.

Development Wells. During 2016, the Company completed 13 gross (13.0 net) productive development wells on the Utah properties. These wells were drilled in 2015. At December 31, 2016, there were no development wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During 2016, the Company did not participate in the drilling of any exploratory wells on the Utah properties. At December 31, 2016, there were no exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth.

Waterflood. In 2016, the Company continued implementing its first waterflood pilot and initiated a second pilot.

Seismic Activity. The Company's 3D seismic coverage in Utah covers approximately 27 square miles, partially covering its properties.

Pennsylvania

As of December 31, 2016, the Company owned oil and gas leases covering 144,000 gross (72,000 net) acres in the Pennsylvania portion of the Appalachian Basin. This acreage is located in the heart of northeast Pennsylvania's Marcellus Shale Gas Trend, principally in Lycoming, Clinton and Centre counties. Of the total acreage position as of December 31, 2016, approximately 19,000 gross (10,000 net) acres were developed, and 125,000 gross (62,000 net) acres were undeveloped. The Company's properties in Pennsylvania are outside operated.

Lease maintenance costs in Pennsylvania were approximately $0.1 million for the year ended December 31, 2016. The Company owns approximately 143,000 gross (71,000 net) acres currently held by production or activities in Pennsylvania.

Development Wells. During 2016, the Company did not participate in the drilling of any development wells on the Pennsylvania properties. At year-end 2016, there were no additional development wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During the year ended December 31, 2016, the Company did not participate in the drilling of any exploratory wells on the Pennsylvania properties. At December 31, 2016, there were no exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2016, 2015, and 2014. The table summarizes the Company's proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2016, 2015 and 2014. During 2014, the Company acquired contracts related to NGLs providing the opportunity to realize the benefit of the NGLs from the gas it produces beginning in 2017. These contracts provide for an annual election to process NGLs; the Company elected not to process NGLs in 2017.

The Company's internal controls for booking proved undeveloped reserves include testing whether the Company has the financial capability to execute PUD drilling. This year, because substantial doubt exists about our ability to continue as a going concern within one year after our December 31, 2016 financial statements are issued, the Company lacks the required degree of certainty of our ability to fund the five-year development program. As a result of our inability to meet the reasonable certainty criteria for recording proved undeveloped reserves as prescribed under the SEC requirements, we did not book any PUD reserves in the December 31, 2016 reserve report. As of February 22, 2017, we are running five rigs in the Pinedale field (four operated, one non-operated) utilizing cash from operations and cash on hand, and, subject to available capital, we intend to continue drilling and completing wells during 2017.

	December 31,		
	2016	2015	2014
	($ amounts in thousands, except per unit data)		
Proved Developed Reserves			
Natural gas (MMcf)	2,321,613	2,336,280	2,245,004
Oil (MBbl)	21,475	22,175	28,481
Natural gas liquids (MBbl)	9,903	9,840	9,118
Proved Undeveloped Reserves			
Natural gas (MMcf)	—	—	2,586,190
Oil (MBbl)	—	—	39,285
Natural gas liquids (MBbl)	—	—	12,875
Total Proved Reserves (MMcfe)(1)	2,509,881	2,528,370	5,369,748
Estimated future net cash flows, before income tax	$ 2,791,229	$ 2,946,982	$ 14,844,349
Standardized measure of discounted future net cash flows, before income taxes(2)	$ 1,690,946	$ 1,865,649	$ 7,097,359
Future income tax	$ —	$ —	$ 1,863,876
Standardized measure of discounted future net cash flows, after income tax	$ 1,690,946	$ 1,865,649	$ 5,233,483
Calculated average price(3)			
Gas ($/Mcf)	$ 2.07	$ 2.21	$ 4.32
Oil ($/Bbl)	$ 37.90	$ 42.36	$ 80.62
NGLs ($/Bbl)	$ 19.17	$ 20.61	$ 46.27

(1) Oil, condensate and NGLs are converted to natural gas at the ratio of one barrel of liquids to six Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas.

(2) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-Generally Accepted Accounting Principle financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable Generally Accepted Accounting Principle ("GAAP") financial measure (standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows before income taxes provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows,

before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(3) As prescribed by SEC rules, our reserve estimates at December 31, 2016, 2015 and 2014, reflect spot prices based on the average of the beginning of the month prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (“EIA”) of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

Proved Undeveloped Reserves

As of December 31, 2016 and 2015, the Company did not include PUD reserves in its total proved reserve estimates due to uncertainty regarding its ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves.

Development plan: The development plan underlying the Company’s proved undeveloped reserves, if any, adopted each year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company’s shareholders.

In addition, as a part of our internal controls for determining a plan to develop our proved reserves each year, we consider whether we have the financial capability to develop proved undeveloped reserves. This year, because substantial doubt exists about our ability to continue as a going concern, we lack the required degree of certainty that we have the ability to fund a development plan. Therefore, as of December 31, 2016, we did not book any PUD reserves. As of February 22, 2017, the Company has 5 rigs running in the Pinedale field (4 operated, 1 non-operated) and, subject to available capital, intends to continue drilling and completing wells. We expect to report PUD reserves in future filings if we determine that we have the financial capability to execute a development plan.

***Conversions*:** At December 31, 2015 the Company did not book any PUD reserves and accordingly there were no conversions of PUD reserves in 2016.

Additions/Extensions: At December 31, 2016 and 2015, the Company did not book any PUD reserves. Accordingly, there were no additions or extensions to the PUD reserve category.

***Revisions*:** At December 31, 2015, the Company did not book any PUD reserves and accordingly there were no revisions to PUD reserves booked during the prior period.

Transfers: At December 31, 2016, the Company did not transfer any reserves to unproven categories, since we did not book any PUD reserves during the prior period.

Internal Controls Over Reserve Estimating Process

Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC’s regulations and GAAP. The Vice President — Development is primarily responsible for overseeing the preparation of the Company’s reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, a Masters of Business Administration and is a licensed Professional Engineer with over 15 years of experience.

The Company’s internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation as well as ultimate approval of our capital budget and review of our development plan by our senior management and Board of Directors. The development plan underlying the Company’s PUD reserves, if any, is further subject to internal controls, including a comparison of future development costs to historical expenditures as well as our future development plan and financial capabilities, and an evaluation of the estimated profitability of each location at the time the report is prepared. The development plan underlying the Company’s proved undeveloped reserves, adopted every year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company’s shareholders.

The estimates of proved reserves and future net revenue as of December 31, 2016 are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The Company engaged Netherland, Sewell & Associates, Inc. (“NSAI”), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company’s assets for the years ended December 31, 2016, 2015 and 2014 in this annual report. For the year ended December 31, 2013, the Company engaged NSAI to prepare the reserve estimates for all of the Company’s assets in Wyoming and Pennsylvania in this annual report. Due to the timing of the closing of the acquisition in Utah in December 2013 relative to the timing of preparing annual corporate reserves, the Company’s Reservoir Engineering Department prepared the proved reserve estimates for its Utah assets for the year ended December 31, 2013, which were prepared in accordance with the Company’s internal controls and SEC regulations and represented less than 2% of estimated proved reserves as of December 31, 2013.

Our internal professional staff works closely with our independent engineers, NSAI, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as an Exhibit to this annual report.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F 2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. He graduated from graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a

Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year ended December 31,		
	2016	2015	2014
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	264,278	268,954	228,517
Oil (Bbl)	2,912	3,533	3,409
Total (Mcfe)	281,748	290,146	248,971
Revenues			
Natural gas sales	$609,756	$696,730	$ 969,850
Oil sales	111,335	142,381	260,170
Total revenues	$721,091	$839,111	$1,230,020
Lease Operating Expenses			
Lease operating expenses (a)	$ 89,134	$106,906	$ 96,496
Liquids gathering system operating lease expense	20,686	20,647	20,306
Severance/production taxes	69,737	72,774	103,898
Gathering	86,809	87,904	59,931
Total lease operating expenses	$266,366	$288,231	$ 280,631
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$ 2.31	$ 3.14	$ 4.03
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$ 2.31	$ 2.59	$ 4.24
Oil ($/Bbl), including realized gains (losses) on commodity derivatives)	$ 38.24	$ 40.31	$ 76.47
Oil ($/Bbl), excluding realized gains (losses) on commodity derivatives)	$ 38.24	$ 40.31	$ 76.32
Costs per Mcfe			
Lease operating expenses	$ 0.32	$ 0.37	$ 0.39
Liquids gathering system operating lease expense	$ 0.07	$ 0.07	$ 0.08
Severance/production taxes	$ 0.25	$ 0.25	$ 0.42
Gathering	$ 0.31	$ 0.30	$ 0.24
Transportation charges	$ 0.07	$ 0.29	$ 0.31
DD&A	$ 0.44	$ 1.38	$ 1.18
General & administrative	$ 0.03	$ 0.03	$ 0.08
Interest	$ 0.24	$ 0.59	$ 0.51
Total costs per Mcfe	$ 1.73	$ 3.28	$ 3.21

The following table sets forth the net sales volumes, operating expenses and realized natural gas prices attributable to field(s) that contain 15% or more of our total estimated proved reserves as of December 31, 2016:

	Year ended December 31,		
	2016	2015	2014
	(In thousands)		
Pinedale Field:			
Production (Mcfe)	256,881	261,498	184,479
Operating expenses	$241,975	$253,214	$228,811
Realized price, excluding hedges ($/Mcf)	$ 2.35	$ 2.66	$ 4.56
Realized price, including hedges ($/Mcf)	$ 2.35	$ 3.24	$ 4.29

(a) Production costs include lifting costs and remedial workover expenses.

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 9, 2017, the Company has long-term natural gas delivery commitments of 2.8 MMMBtu in 2018 under existing agreements. As of February 9, 2017, the Company has long-term crude oil delivery commitments of 1.6 MMBbls in 2017, 1.7 MMBbls in 2018 and 0.3 MMBbls in 2019 under existing agreements. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Productive Wells

As of December 31, 2016 the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas	2,835	1,876
Crude Oil	146	146
Total	2,981	2,022

* Productive wells are producing wells, shut-in wells the Company deems capable of production, wells that are waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests the company owns in gross wells.

Oil and Gas Acreage

The primary terms of the Company's oil and gas leases expire at various dates. Much of the Company's undeveloped acreage is held by production, which means that the Company will maintain its rights in these leases as long as oil or natural gas is produced from the acreage by it or by other parties holding interests in producing wells on those leases. In some cases, if production from a lease ceases, the lease will expire, and in some cases, if production from a lease ceases, the Company may maintain the lease by additional operations on the acreage.

The Company does not believe the remaining terms of its leases are material. The Company expects to maintain essentially all of the material leases among its oil and gas properties by production, operations, extensions or renewals. The Company does not expect to lose material lease acreage because of failure to drill due to inadequate capital, equipment or personnel. The Company has, based on its evaluation of prospective economics, allowed acreage to expire and it may allow additional acreage to expire in the future. The Company estimates that approximately 500 net acres of leases in Pennsylvania, 200 net acres of leases in Colorado, 500 net acres of leases in Utah, and 1,000 net acres of leases in Wyoming may expire in 2017.

As of December 31, 2016 the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	35,000	23,000	70,000	46,000
Pennsylvania	19,000	10,000	125,000	62,000
Utah	5,000	5,000	4,000	3,000
All States	59,000	38,000	199,000	111,000

Drilling Activities

For each of the three fiscal years ended December 31, 2016, 2015 and 2014 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	184.0	132.3	121.0	76.5
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	184.0	132.3	121.0	76.5

At year end, there were no development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	94.0	68.6	7.0	3.8	25.0	13.4
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	94.0	68.6	7.0	3.8	25.0	13.4

At year end, there were 26 gross (20.1 net) additional exploratory wells that were either drilling or had operations suspended in the Pinedale field.

Utah

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	14.0	14.0	0.0	0.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	14.0	14.0	0.0	0.0

At year end, there were no additional development wells that were either drilling or had operations suspended.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.0	0.0	5.0	5.0	74.0	74.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	5.0	5.0	74.0	74.0

At year end, there were no additional exploratory wells that were either drilling or had operations suspended.

Pennsylvania

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	0.0	0.0	5.0	2.5
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	5.0	2.5

At year end, there were no additional development wells that were either drilling or had operations suspended.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.0	0.0	0.0	0.0	1.0	0.5
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	1.0	0.5

At year end, there were no additional exploratory wells that were either drilling or had operations suspended.

Colorado

The Company did not conduct any operations on this acreage during 2016, 2015 or 2014. During 2014, the Company sold the surface rights to its Colorado acreage and retained the mineral rights. The Company has no immediate plans for further exploration in this area during 2017.

Present Activities

Our present activities primarily involve continued production operations on our Pinedale field. As of February 22, 2017, the Company has 5 rigs running in the Pinedale field (4 operated, 1 non-operated). Please refer to Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources for further discussion.

Item 3. ***Legal Proceedings.***

Other Claims: See Note 11 and Note 13 for additional discussion of on-going claims and disputes in our chapter 11 proceedings, certain of which may be material. The Company is also currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine or predict the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position, or results of operations.

Item 4. ***Mine Safety Disclosures.***

None.

PART II

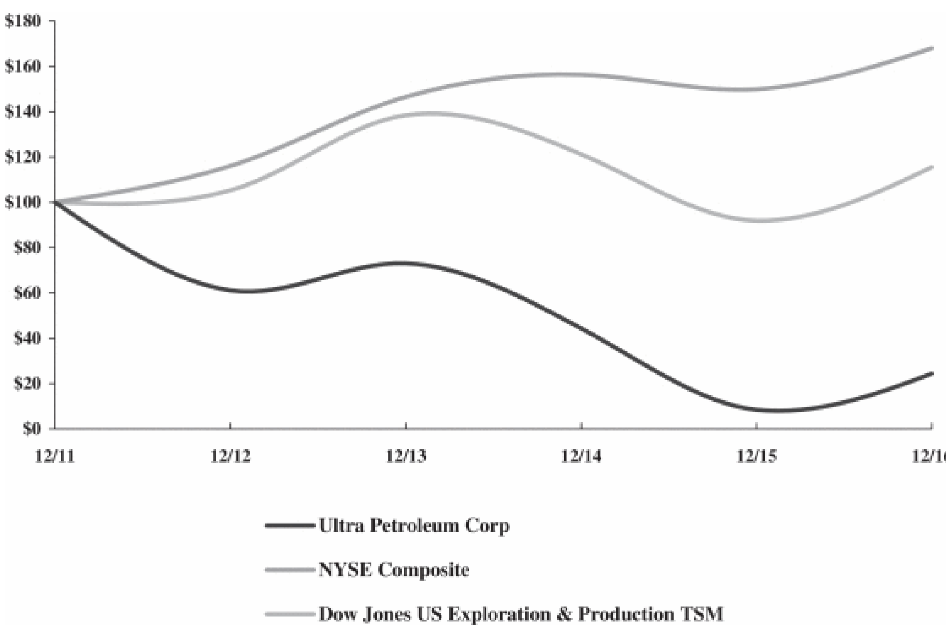
Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

The Company's common shares traded on the New York Stock Exchange (the "NYSE") under the symbol "UPL" through May 3, 2016 and subsequently have traded over-the-counter ("OTC") under the symbol "UPLMQ". The following table sets forth the high and low intra-day sales prices of the common shares for the periods indicated.

2016	High	Low
1st quarter	$ 2.64	$ 0.18
2nd quarter	$ 2.14	$ 0.16
3rd quarter	$ 5.17	$ 1.62
4th quarter	$ 8.49	$ 3.64
2015	**High**	**Low**
1st quarter	$17.43	$11.31
2nd quarter	$18.04	$12.43
3rd quarter	$12.66	$ 5.86
4th quarter	$ 7.91	$ 1.85

As of February 15, 2017, the last reported sales price of the common shares on the OTC was $8.30 per share and there were approximately 329 holders of record of the common shares. The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common shares in the near future. The Company intends to retain its cash flow from operations for the future operation and development of its business.

The following share price performance graph is intended to allow review of shareholder returns, expressed in terms of the appreciation of the Company's common shares relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future share performance. The graph compares the yearly percentage change in the cumulative total shareholder return on the Company's common shares with the cumulative total return of the NYSE Composite Index and of the Dow Jones U.S. Exploration and Production TSM Index from December 31, 2011 through December 31, 2016.



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Item 6. ***Selected Financial Data.***

The selected consolidated financial information presented below for the years ended December 31, 2016, 2015, 2014, 2013 and 2012 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 609,756	$ 696,730	$ 969,850	$ 824,266	$ 695,733
Oil sales	111,335	142,381	260,170	109,138	114,241
Total operating revenues	721,091	839,111	1,230,020	933,404	809,974
Expenses:					
Production expenses and taxes	266,366	288,231	280,631	212,578	184,229
Transportation charges	20,049	83,803	77,780	82,797	84,470
Depletion, depreciation and amortization	125,121	401,200	292,951	243,390	388,985
Ceiling test and other impairments	—	3,144,899	—	—	2,972,464
General and administrative	3,617	3,259	13,602	12,606	14,348
Stock compensation	5,562	4,128	5,467	9,767	10,756
Interest expense	66,565	171,918	126,157	101,486	88,180
Total operating expenses	487,280	4,097,438	796,588	662,624	3,743,432
Other:					
Gain (loss) on commodity derivatives	—	42,611	82,402	(46,754)	73,581
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553	10,553	—
Contract cancellation fees	—	—	—	—	(15,469)
Contract settlement	(131,106)	—	—	—	—
Gain on sale of property	—	—	8,022	—	—
Litigation expense	—	(4,401)	—	—	—
Restructuring expenses	(7,176)	—	—	—	—
Reorganization items, net	(47,503)	—	—	—	—
Other (expense) income, net	(3,082)	(2,060)	2,618	(357)	(1,765)
Total other (expense) income, net	(178,314)	46,703	103,595	(36,558)	56,347
Income (loss) before income taxes	55,497	(3,211,624)	537,027	234,222	(2,877,111)
Income tax (benefit)	(654)	(4,404)	(5,824)	(3,616)	(700,213)
Net income (loss)	$ 56,151	$ (3,207,220)	$ 542,851	$ 237,838	$ (2,176,898)
Basic Earnings (Loss) per Share:					
Net income (loss) per common share — basic	$ 0.37	$ (20.94)	$ 3.54	$ 1.55	$ (14.24)
Fully Diluted Earnings (Loss) per Share:					
Net income (loss) per common share — fully diluted	$ 0.36	$ (20.94)	$ 3.51	$ 1.54	$ (14.24)
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 307,614	$ 515,538	$ 712,584	$ 472,638	$ 654,825
Investing activities	$ (278,900)	$ (512,757)	$ (1,600,743)	$ (1,093,519)	$ (577,223)
Financing activities	$ 368,621	$ (7,557)	$ 886,414	$ 618,624	$ (75,988)
Balance Sheet Data:					
Cash and cash equivalents	$ 401,478	$ 4,143	$ 8,919	$ 10,664	$ 12,921
Working capital (deficit)	$ 383,185	$ (3,560,683)	$ (168,580)	$ (278,845)	$ (388,244)
Oil and gas properties	$ 1,010,466	$ 851,145	$ 3,878,937	$ 2,421,611	$ 1,657,500
Total assets	$ 1,540,928	$ 952,039	$ 4,225,690	$ 2,785,319	$ 2,007,345
Total debt(1)(2)	$ —	$ 3,390,000	$ 3,378,000	$ 2,470,000	$ 1,837,000
Other long-term obligations	$ 177,088	$ 165,784	$ 152,472	$ 91,932	$ 76,038
Deferred income taxes, net	$ —	$ —	$ 992	$ —	$ —
Total shareholders' (deficit) equity	$ (2,928,151)	$ (2,991,937)	$ 211,660	$ (331,490)	$ (577,867)

(1) At December 31, 2016, $3.8 billion of long-term debt is included with liabilities subject to compromise on our Consolidated Balance Sheets. See Note 1.

(2) At December 31, 2015, costs associated with the issuance of our Senior Notes, 2018 Notes and 2024 Notes are presented as a direct deduction from the carrying value of the related debt liability on the Consolidated Balance Sheet.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion of the financial condition and operating results of the Company should be read in conjunction with the consolidated financial statements and related notes of the Company, which are included in this report in Item 8, and the information set forth in Risk Factors under Item 1A. Except as otherwise indicated, all amounts are expressed in U.S. dollars.

Overview

Ultra Petroleum Corp. is an independent exploration and production company focused on developing its long-life natural gas reserves in the Green River Basin of Wyoming — the Pinedale and Jonah fields — its oil reserves in the Uinta Basin in Utah and its natural gas reserves in the Appalachian Basin of Pennsylvania. The Company operates in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company currently conducts operations exclusively in the United States. Substantially all of its oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company's proportionate interest in such activities. The Company continues to focus on improving its drilling and production results through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience into improved operational efficiencies. Inflation has not had, nor is it expected to have in the foreseeable future, a material impact on the Company's results of operations.

The Company currently generates its revenue, earnings and cash flow primarily from the production and sales of natural gas and condensate from its properties in southwest Wyoming with a portion of the Company's revenues coming from oil sales from its properties in the Uinta Basin in Utah, acquired in December 2013, and gas sales from wells located in the Appalachian Basin in Pennsylvania. Additionally, during 2014, the Company acquired contracts related to NGLs providing the opportunity to realize the benefit of the NGLs from the gas it produces beginning in 2017. The Company elected not to process NGLs in 2017.

The prices of oil and natural gas are critical factors to the Company's business. The prices of oil and natural gas have historically been volatile, and this volatility could be detrimental to the Company's financial performance. As a result, and from time to time, the Company tries to limit the impact of this volatility on its results by entering into swap agreements and/or fixed price forward physical delivery contracts for natural gas and oil. (See Note 7).

The average price realization for the Company's natural gas during 2016 was $2.31 per Mcf. During the quarter ended December 31, 2016, the average price realization for the Company's natural gas was $2.87 per Mcf. The Company did not have any open commodity derivative contracts during the year ended December 31, 2016.

The average price realization for the Company's crude oil and condensate during 2016 was $38.24 per barrel. During the quarter ended December 31, 2016, the average price realization for the Company's crude oil and condensate was $45.27 per barrel.

Chapter 11 Proceedings, Ability to Continue as a Going Concern

Chapter 11 Proceedings

On April 29, 2016 (the "Petition Date"), to restructure their respective obligations and capital structures, the Company and each of its direct and indirect wholly owned subsidiaries (collectively, the "Ultra Entities" or "Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Debtors' chapter 11 cases are being jointly administered for procedural purposes under the caption In re Ultra

Petroleum Corp., et al, Case No. 16-32202 (MI) (Bankr. S.D. Tex.). Information about our chapter 11 cases is available at our website (www.ultrapetroleum.com) and also at a website maintained by our claims agent, Epiq Systems (http://dm.epiq11.com/UPT/Docket).

We are currently operating our business as a debtor-in-possession in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. After we filed our chapter 11 petitions, the Bankruptcy Court granted certain relief we requested enabling us to conduct our business activities in the ordinary course, including, among other things and subject to the terms and conditions of such orders, authorizing us to pay employee wages and benefits, pay taxes and certain governmental fees and charges, continue to operate our cash management system in the ordinary course, remit funds we hold from time to time for the benefit of third parties (such as royalty owners), and pay the prepetition claims of certain of our vendors that hold liens under applicable non-bankruptcy law. For goods and services provided following the Petition Date, we intend to pay vendors in full under normal terms.

Subject to certain exceptions provided for in section 362 of the Bankruptcy Code, all judicial and administrative proceedings against us or our property were automatically enjoined, or stayed, as of the Petition Date. In addition, the filing of new judicial or administrative actions against us or our property for claims arising prior to the date on which our chapter 11 cases were filed were automatically enjoined. This prohibits, for example, our lenders or noteholders from pursuing claims for defaults under our debt agreements and our contract counterparties from pursuing claims for defaults under our contracts. Accordingly, unless the Bankruptcy Court agrees to lift the automatic stay, all of our prepetition liabilities and obligations should be settled or compromised under the Bankruptcy Code as part of our chapter 11 proceedings.

Our operations and ability to execute our business remain subject to the risks and uncertainties described in Item 1A, “Risk Factors”. In addition, our assets, liabilities, including our capital structure, shareholders, officers and/or directors could change materially because of our chapter 11 cases. In addition, the description of our operations, properties and capital plans included in this Annual Report on Form 10-K may not accurately reflect our operations, properties and capital plans after we emerge from chapter 11.

Creditors’ Committees — Appointment & Formation

On May 5, 2016, the United States Trustee for the Southern District of Texas appointed an official committee for unsecured creditors of all of the Debtors (the “UCC”). On September 26, 2016, the United States Trustee for the Southern District of Texas filed a Notice of Reconstitution of the UCC. In addition, certain other stakeholders have organized for purposes of participating in the Debtors’ chapter 11 cases: (i) on June 8, 2016, an informal ad hoc committee of unsecured creditors of our subsidiary, Ultra Resources (“Ultra Resources”), notified the Bankruptcy Court it had formed and identified its members, most of which are distressed debt investors and/or hedge funds; (ii) on June 13, 2016, an informal ad hoc committee of the holders of senior notes issued by the Company notified the Bankruptcy Court it had formed and identified its members; (iii) on July 20, 2016, an informal ad hoc committee of shareholders of the Company notified the Bankruptcy Court it had formed and identified its members; and (iv) on January 6, 2017, an informal ad hoc committee of unsecured creditors of our subsidiary, Ultra Resources, notified the Bankruptcy Court it had formed and identified its members, most of which are insurance companies. We expect each of the committees to be involved in our chapter 11 cases, and any disagreements with any of the committees may extend our chapter 11 cases, increase the cost of our chapter 11 cases, and/or delay our emergence from chapter 11.

Exclusivity

The Bankruptcy Code provides chapter 11 debtors-in-possession with the exclusive right to file a plan of reorganization under chapter 11 through a period of time specified in the Bankruptcy Code, which period may be extended by the Bankruptcy Court. On July 27, 2016, we filed a motion seeking an extension of the exclusive chapter 11 plan filing period. At a hearing conducted on August 25, 2016, the Bankruptcy Court extended our exclusive right to file a plan of reorganization under chapter 11 through and including March 1, 2017, and to solicit acceptances of such plan through and including May 1, 2017, subject to our producing and delivering a long-term business plan prior to December 1, 2016. The long-term business plan was provided prior to December 1, 2016, and, pursuant to a Stipulation Regarding Order Extending Exclusivity signed by the Bankruptcy Court, we satisfied the condition (with the effect that our exclusive right to file a reorganization plan now continues until and including March 1, 2017, and our exclusive right to solicit acceptances of such a plan continues until and including May 1, 2017). On February 1, 2017, we filed a motion seeking an extension of the exclusive chapter 11 plan filing period through June 29, 2017 and the exclusive right to solicit acceptances of a chapter 11 plan through August 29, 2017. On February 17, 2017, we filed a revised proposed form of order to the motion seeking an extension of the exclusive chapter 11 plan filing period through April 15, 2017 and the exclusive right to solicit acceptances of a chapter 11 plan through June 15, 2017.

Plan Support Agreement, Rights Offering, Backstop Commitment Agreement and Exit Financing Commitment Letter

On November 21, 2016, each of the Ultra Entities entered into a Plan Support Agreement ("PSA") with (i) holders of at least 66.67% of the principal amount of the Company's outstanding 5.750% Senior Notes due 2018 and 6.125% Senior Notes due 2024 and (ii) shareholders who own at least a majority of the Company's outstanding common stock or the economic interests therein (collectively, the "Plan Support Parties") and a Backstop Commitment Agreement ("BCA") with a subset thereof (collectively, the "Commitment Parties").

Plan Support Agreement: The PSA sets forth the terms and conditions pursuant to which the Ultra Entities and the Commitment Parties have agreed to seek and support a joint plan of reorganization at an aggregate plan value of $6.25 billion, $6.0 billion, or $5.5 billion, depending on commodity prices, for the Ultra Entities which will successfully complete the Reorganization Proceedings (collectively, the "Plan"). Under the Plan, the total enterprise value of the Ultra Entities will be $6.0 billion (the "Plan Value"); provided, that if the average closing price of the 12-month forward Henry Hub natural gas strip price during the seven (7) trading days preceding the commencement of the Rights Offering solicitation is: (i) greater than $3.65/MMBtu, the Plan Value will be $6.25 billion; or (ii) less than $3.25/MMBtu, the Plan Value will be $5.5 billion.

Among other matters, the Plan provides for a comprehensive restructuring of all allowable claims against and interests in the Ultra Entities, including the conversion of the outstanding unsecured senior notes issued by the Company ("HoldCo Notes" and, the holders thereof, "HoldCo Noteholders") to newly-issued shares of common stock in the Company, the exchange of the outstanding unsecured senior notes issued by UPL's subsidiary Ultra Resources for a combination of new unsecured notes issued by Ultra Resources and cash, the payment in full of all other allowed claims against the Ultra Debtors in cash, and the distribution to each owner of common stock in the Company as of the Plan's record date ("HoldCo Equityholders") of such owner's pro rata share of the new UPL common stock and the right to participate in the Rights Offering (as described below).

The PSA provides certain milestones for the restructuring, which the Company is required to use commercially reasonable efforts to satisfy. Failure of the Company to satisfy certain milestones, including (i) entry of an order approving the Debtors' entry into the BCA by January 20, 2017 and (ii) consummation of the Plan by April 15, 2017 would provide the Plan Support Parties a termination right under the PSA.

On February 9, 2017, the Company entered into the First Amendment to the Plan Support Agreement (the "PSA Amendment") with the Plan Support Parties party thereto. Pursuant to the PSA Amendment, the Required Consenting Parties agreed that the Plan Term Sheet, as modified to accord with the treatment of OpCo Funded Debt Claims and General Unsecured Claims under the Second Amended Plan, is reasonably satisfactory to such parties (as such terms are defined in the Plan Support Agreement).

On February 13, 2017, the Court signed an order approving our Disclosure Statement. On February 21, 2017, the Court signed an amended order approving our Disclosure Statement. The amended order: (1) approves the adequacy of our Disclosure Statement, (2) approves the solicitation and notice procedures related to confirmation of our plan of reorganization, (3) approves the forms of ballots and notices related thereto, (4) approves the rights offering procedures and matters related thereto, (5) schedules certain dates related to our plan confirmation process and Rights Offering, and (6) grants related relief. With respect to the Rights Offering, the amended order defines the "Subscription Commencement Date" as February 21, 2017. Accordingly, as will be reflected in the materials to be distributed in connection with the Rights Offering, the Plan Value under the PSA is $6.0 billion.

Rights Offering: In accordance with the Plan, the BCA and the Rights Offering procedures submitted by the Company in connection with the Plan, the Company will offer eligible debt and equity holders, including the Commitment Parties, the right to purchase shares of new common stock in the Company upon effectiveness of the Plan for an aggregate purchase price of $580.0 million. The Rights Offering will consist of the following offerings:

- HoldCo Noteholders shall be granted rights (the "HoldCo Noteholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Noteholder Rights Offering Shares"), which HoldCo Noteholder Rights Offering Shares, collectively, will reflect an aggregate purchase price of $435.0 million.
- HoldCo Equityholders shall be granted rights (the "HoldCo Equityholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Equityholder Rights Offering Shares" and, together with the HoldCo Noteholder Rights Offering Shares, the "Rights Offering Shares"), which HoldCo Equityholder Rights Offering Shares, collectively, will reflect an aggregate purchase price of $145.0 million.

Backstop Commitment Agreement: Under the BCA, the Commitment Parties have agreed to purchase the HoldCo Noteholder Rights Offering Shares and the HoldCo Equityholder Rights Offering Shares, as applicable, that are not duly subscribed for pursuant to the HoldCo Noteholder Rights Offering or the HoldCo Equityholder Rights Offering, as applicable, by parties other than Commitment Parties (the "Backstop Commitment") at an implied 20% discount to the Plan Value, which is the price for the rights offering set forth in the PSA (the "Rights Offering Price").

The Company will pay the Commitment Parties upon the closing of the Rights Offering a Commitment Premium equal to 6.0% of the $580.0 million committed amount (the "Commitment Premium"). The Commitment Premium was fully earned as of January 19, 2017, the date the Backstop Approval Order was entered by the Bankruptcy Court. The Commitment Premium will be paid either in the form of new common stock at the Rights Offering Price, if the Plan is consummated as contemplated in the Plan Support Agreement, or in cash in the amount of 4.0% of the $580.0 million committed amount, if the Backstop Agreement is terminated other than as a result of a material breach by the Commitment Parties.

Exit Financing Commitment Letter: On February 8, 2017, the Debtors obtained a commitment letter (the "Commitment Letter") from Barclays Bank PLC (including any affiliates that may perform its responsibilities thereunder, "Barclays"), pursuant to which, in connection with the consummation of the Plan, Barclays has agreed to provide secured and unsecured financing in an aggregate amount of up to $2.4 billion, consisting of:

- A seven-year senior secured first lien term loan credit facility (the "Term Loan Facility") in an aggregate amount of $600.0 million;
- A five-year senior secured first lien revolving credit facility (the "Revolving Facility") in an aggregate amount of $400.0 million with an initial borrowing base (the "Borrowing Base") (which limits the aggregate amount of first lien debt under the Revolving Facility and the Term Loan Facility) of $1.0 billion with scheduled semi-annual redeterminations starting on October 1, 2017; and
- Senior unsecured bridge loans under senior unsecured bridge facilities (together with the Revolving Facility and the Term Loan Facility, the "Credit Facilities") in an aggregate amount of $1.4 billion,

consisting of (i) a five-year bridge facility in an aggregate principal amount of $700.0 million, less the aggregate principal amount of privately placed five-year senior unsecured notes of the Company, if any, issued on or prior to the closing date of the Credit Facilities (the "Closing Date") and (ii) an eight-year bridge facility in an aggregate principal amount of $700.0 million, less the aggregate principal amount of privately placed eight-year senior unsecured notes of the Company, if any, issued on or prior to the Closing Date.

The Revolving Facility is anticipated to, among other things:

- have capacity for the Debtors to increase the commitments subject to certain conditions;
- have $100.0 million of the commitments available for the issuance of letters of credit; and
- require the Company to maintain (A) a maximum total net debt to EBITDAX ratio of (i) 4.25 to 1.0 as of the end of the first full fiscal quarter after the closing date and each subsequent fiscal quarter of 2017 and (ii) 4.0 to 1.0 as of the end of each fiscal quarter thereafter, (B) a minimum current ratio of 1.0 to 1.0 and (C) a minimum interest coverage ratio of 2.5 to 1.0.

The Term Loan Facility is anticipated to, among other things, have capacity for the Debtors to increase the commitments, with such increase in commitments subject to certain conditions.

The Revolving Facility and Term Loan Facility will include customary affirmative and negative covenants, including, among other things, as to compliance with laws, delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of properties (including oil and gas properties), maintenance of a lien on, and delivery of title information with respect to, 85% of the Debtors' proved oil and gas reserves, restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants.

The Revolving Facility and Term Loan Facility will include events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to material indebtedness; bankruptcy; material judgments; and certain ERISA events. Many events of default are subject to customary notice and cure periods.

The commitments of Barclays to provide the Credit Facilities are subject to certain conditions set forth in the Commitment Letter, including but not limited to the Plan Support Parties' reasonable satisfaction with the approval by the Bankruptcy Court of all actions to be taken, undertakings to be made and obligations to be incurred by the Debtors in connection with the Credit Facilities.

The Commitment Letter will terminate upon the occurrence of certain events described therein and the outside termination date for the Commitment Letter is May 9, 2017.

Based on the indicative pricing levels provided to the Company, the blended interest rate of the Credit Facilities on the effective date of the Plan (the "Blended Rate") is expected to be approximately 5.10% per annum. The actual Blended Rate on the effective date of the Plan will depend on factors including, without limitation, the size of each tranche of the Credit Facilities and the results of the syndication process of such Credit Facilities, and may therefore be higher or lower than 5.10% per annum.

As previously disclosed on a Current Report on Form 8-K filed with the SEC on February 9, 2017, on February 8, 2017, the Debtors filed a motion with the Bankruptcy Court seeking authorization to enter into and perform under the Commitment Letter and the other commitment papers. The motion was heard and approved during the Company's disclosure statement hearing on February 13, 2017.

Plan of Reorganization (Disclosure Statement)

We plan to emerge from our chapter 11 cases after we obtain approval from the Bankruptcy Court for a chapter 11 plan of reorganization. Among other things, a chapter 11 plan of reorganization will determine the rights and satisfy the claims of our prepetition creditors and security holders. The terms and conditions of a chapter 11 plan of reorganization will be determined through negotiations with our stakeholders and, possibly, decisions by the Bankruptcy Court.

On December 6, 2016, we filed an initial plan of reorganization and disclosure statement therefore. On January 17, 2017, we filed a revised plan of reorganization and disclosure statement therefore. On February 8, 2017, we filed a further revised plan of reorganization and disclosure statement therefore. On February 13, 2017, we filed amendments and further revisions to the plan of reorganization we filed on February 8, 2017 (the "Plan") and to the disclosure statement therefore (the "Disclosure Statement"). The Court approved our Disclosure Statement on February 13, 2017 and scheduled a hearing to consider confirmation of the Plan for March 14, 2017.

Under the absolute priority scheme established by the Bankruptcy Code, unless our creditors agree otherwise, all of our prepetition liabilities and postpetition liabilities must be satisfied in full before the holders of our existing common stock can receive any distribution or retain any property under a chapter 11 plan of reorganization. The ultimate recovery to creditors and/or shareholders, if any, will not be determined until confirmation and implementation of a plan or plans of reorganization. We can give no assurance that any recovery or distribution of any amount will be made to any of our creditors or shareholders. Our plan of reorganization could result in any of the holders of our liabilities and/or securities, including our common stock, receiving no distribution on account of their interests and cancellation of their holdings. Moreover, a plan of reorganization can be confirmed, under the Bankruptcy Code, even if the holders of our common stock vote against the plan and even if the plan provides that the holders of our common stock receive no distribution on account of their equity interests.

Liabilities Subject to Compromise

We have applied Accounting Standards Codification ("ASC") 852, Reorganizations, in preparing the Consolidated Financial Statements included in this Annual Report on Form 10-K. In addition, the consolidated financial statements presented here include amounts classified as "liabilities subject to compromise." This amount represents estimates of known or potential prepetition claims expected to be resolved in connection with our chapter 11 proceedings. Additional amounts may be included in liabilities subject to compromise in future periods if we elect to reject executory contracts and unexpired leases as part of our chapter 11 cases. Due to the uncertain nature of many of the potential claims, the magnitude of potential claims is not reasonably estimable at this time. Potential claims not currently included with liabilities subject to compromise in our Consolidated Balance Sheets may be material. In addition, differences between amounts we are reporting as liabilities subject to compromise in this Annual Report on Form 10-K and the amounts attributable to such matters claimed by our creditors or approved by the Bankruptcy Court may be material. We will continue to evaluate our liabilities throughout the chapter 11 process, and we plan to make adjustments in future periods as necessary and appropriate. Such adjustments may be material.

Under the Bankruptcy Code, we may assume, assign, or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court and certain other conditions. If we reject a contract or lease, such rejection generally (1) is treated as a prepetition breach of the contract or lease, (2) subject to certain exceptions, relieves the Debtors of performing their future obligations under such contract or lease, and (3) entitles the counterparty thereto to a prepetition general unsecured claim for damages caused by such deemed breach. If we assume an executory contract or unexpired lease, we are generally required to cure any existing monetary defaults under such contract or lease and provide adequate assurance of future performance to the counterparty. Accordingly, any description of an executory contract or unexpired lease in this Annual Report on

Form 10-K, including any quantification of our obligations under any such contract or lease, is wholly qualified by the rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and we expressly preserve all of our rights with respect thereto.

The following table summarizes the components of liabilities subject to compromise included in our Consolidated Balance Sheets as of December 31, 2016:

	December 31, 2016
Accounts payable	$ 1,322
Accrued liabilities	6,303
Accrued interest payable	99,774
Debt	3,759,000
Accrued contract settlements	171,642
Liabilities subject to compromise	$ 4,038,041

Schedules and Statements — Magnitude of Potential Claims & Claims Resolution Process

On June 8, 2016, each of the Debtors filed a Schedule of Assets and Liabilities and Statement of Financial Affairs (collectively, the "Schedules and Statements") with the Bankruptcy Court setting forth, among other things, the assets and liabilities of the Debtors, subject to the assumptions filed in connection therewith. On October 14, 2016, Ultra Wyoming LGS, LLC ("UWLGS"), one of the Debtors and our indirect, wholly owned subsidiary, filed an amendment to its Schedules and Statements. The Schedules and Statements are subject to further amendment or modification. Certain holders of prepetition claims were required to file proofs of claim by the deadline for filing certain proofs of claims in the Debtors' chapter 11 cases, which deadline was September 1, 2016, for prepetition general unsecured claims and October 26, 2016, for governmental claims. Differences between amounts scheduled by the Debtors and claims by creditors will be investigated and resolved in connection with the claims resolution process. In light of the expected number of creditors, the claims resolution process may take considerable time to complete and will likely continue after our emergence from bankruptcy. Accordingly, the ultimate number and amount of allowed claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

To the best of our knowledge, we have notified all of our known current or potential creditors that the Debtors have filed chapter 11 cases. The Schedules and Statements set forth, among other things, the assets and liabilities of each of the Debtors, including executory contracts to which each of the Debtors is a party, and are subject to the qualifications and assumptions included therein and amendment or modification as our chapter 11 cases proceed.

Through the claims resolution process, differences in amounts scheduled by the Debtors and claims filed by creditors will be investigated and resolved, including through the filing of objections with the Bankruptcy Court where appropriate.

Many of the claims identified in the Schedules and Statements are listed as disputed, contingent or unliquidated. In addition, there are differences between the amounts for certain claims listed in the Schedules and Statements and the amounts claimed by our creditors. Such differences, as well as other disputes and contingencies will be investigated and resolved as part of our claims resolution process in our chapter 11 cases. Please refer to Note 11 for additional information about contingent matters and commitments related to certain claims filed in our chapter 11 cases.

Pursuant to the Federal Rules of Bankruptcy Procedure, some creditors who wished to assert prepetition claims against us and whose claims (i) were not listed in the Schedules and Statements or (ii) were listed in the

Schedules and Statements as disputed, contingent, or unliquidated, were required to file a proof of claim with the Bankruptcy Court prior to the bar date set by the court. The bar date for non-governmental creditors was September 1, 2016, and the bar date for governmental creditors was October 26, 2016.

The claims filed against the Debtors to date are voluminous. Further, it is possible that claimants will file amended or modified claims in the future, including modifications or amendments to assign values to claims originally filed with no designated value. The amended or modified claims may be material.

We plan to investigate and evaluate all filed claims in connection with our plan of reorganization. As a part of the claims resolution process, we anticipate working to resolve differences in amounts we listed in our Schedules and Statements and amounts of claims filed by our creditors. We have already identified, for example, claims that we believe should be disallowed by the Bankruptcy Court because they are duplicative, have been later amended or superseded, are without merit, are overstated or for other reasons. We have previously filed, and we will continue to file and prosecute, objections with the Bankruptcy Court as necessary for claims we believe should be disallowed.

Tax Attributes; Net Operating Loss Carryforwards

We have substantial tax net operating loss carryforwards and other tax attributes. Under the U.S. Internal Revenue Code, our ability to use these net operating losses and other tax attributes may be limited if we experience a change of control, as determined under U.S. Internal Revenue Code. Accordingly, we obtained an order from the Bankruptcy Court that is intended to protect our ability to use our tax attributes by imposing certain notice procedures and transfer restrictions on the trading of the Company’s common stock.

In general, the order applies to any person or entity that, directly or indirectly, beneficially owns (or would beneficially own as a result of a proposed transfer) at least 4.5% of the Company’s common stock. Such persons are required to notify us and the Bankruptcy Court before effecting a transaction that might result in us losing the ability to use our tax attributes, and we have the right to seek an injunction to prevent the transaction if it might adversely affect our ability to use our tax attributes.

Any purchase, sale or other transfer of our equity securities in violation of the restrictions of the order is null and would be treated as invalid from the outset as an act in violation of a Bankruptcy Court order and would therefore confer no rights on a proposed transferee.

Costs of Reorganization

We have incurred and will continue to incur significant costs associated with our reorganization and the chapter 11 proceedings. We expect these costs, which are being expensed as incurred, will significantly affect our results of operations. In addition, a non-cash charge to write-off the unamortized debt issuance costs related to our funded indebtedness is included in “Reorganization items, net” as these debt instruments are expected to be impacted by the pendency of the Company’s chapter 11 cases. For additional information about the costs of our reorganization and chapter 11 proceedings, see “Reorganization items, net” below.

The following table summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the years ended December 31, 2016:

	For the Year Ended December 31,		
	2016	2015	2014
Professional fees(1)	$11,781	$ —	$ —
Deferred financing costs(2)	18,742	—	—
Contract settlements(3)	17,350	—	—
Other(4)	(370)	—	—
Total Reorganization items, net	$47,503	$ —	$ —

(1) The year ended December 31, 2016 includes $6.4 million directly related to accrued, unpaid professional fees associated with the chapter 11 filings.

(2) A non-cash charge to write-off all of the unamortized debt issuance costs related to the unsecured Credit Agreement, unsecured Senior Notes issued by Ultra Resources, the unsecured 2018 Senior Notes issued by the Company and the unsecured 2024 Senior Notes issued by the Company is included in Reorganization items, net as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

(3) Includes accrued, unpaid amounts subject to Bankruptcy Court approval related to a settlement reached with Big West Oil, LLC in the amount of $17.35 million.

(4) Cash interest income earned for the period after the Petition Date on excess cash over normal invested capital.

Ability to Continue as a Going Concern

The Consolidated Financial Statements included in this Annual Report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The Consolidated Financial Statements do not reflect any adjustments that might result from the outcome of our chapter 11 proceedings. We have significant indebtedness, all of which we have reclassified to liabilities subject to compromise at December 31, 2016. Our level of indebtedness has adversely impacted and is continuing to adversely impact our financial condition. As a result of our financial condition, the defaults under our debt agreements, and the risks and uncertainties surrounding our chapter 11 proceedings, substantial doubt exists that we will be able to continue as a going concern.

Critical Accounting Policies

The discussion and analysis of the Company's financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. GAAP. In addition, application of GAAP requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates related to judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated. Set forth below is a discussion of the critical accounting policies used in the preparation of our financial statements which we believe involve the most complex or subjective decisions or assessments.

Oil and Gas Reserves. The reserve estimates presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance according to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities — Oil and Gas ("FASB ASC 932") as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995.

The Company utilizes reliable technology such as seismic data and interpretation, wireline formation tests, geophysical logs and core data to assess its resources. However, none of these technologies have contributed to a material addition to the proved reserves in this report.

Estimates of proved crude oil and natural gas reserves significantly affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves may result from a number of factors including lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

The Company's proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, the estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting. The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Additives — Oil and Gas ("FASB ASC 932"). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded on the fair value of the asset retirement obligation when incurred. Gain or loss or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company's proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

Write-down of Oil and Gas Properties. Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

During 2015, the Company recorded a $3.1 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials. The Company did not have any write-downs related to the full cost ceiling limitation in 2016 or 2014.

Deferred Financing Costs. During the year ended December 31, 2016, a non-cash charge to write-off all of the unamortized debt issuance costs related to the unsecured Credit Agreement, unsecured Senior Notes (as defined below) issued by Ultra Resources, Inc., the unsecured 2018 Senior Notes (as defined below) issued by the Company and the unsecured 2024 Senior Notes (as defined below) issued by the Company is included in Reorganization items, net in the accompanying Consolidated Statements of Operations as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases. At December 31, 2015, other current assets includes costs associated with the issuance of our revolving credit facility while costs associated with the issuance of our Senior Notes, 2018 Notes and 2024 Notes are presented as a direct deduction from the carrying amount of the related debt liability.

Asset Retirement Obligation. The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. FASB ASC Topic 410, Asset Retirement and Environmental Obligations ("FASB ASC 410") requires that the discounted fair value of a liability for an ARO 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 natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements; the credit-adjusted, risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company 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 passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Natural Gas Sales. The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances.

Valuation of Deferred Tax Assets. The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax basis (temporary differences).

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. 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 recorded a valuation allowance against certain deferred tax assets of $1.3 billion as of December 31, 2016. Some or all of this valuation allowance may be reversed in future periods against future income.

Derivative Instruments and Hedging Activities. The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives.

Fair Value Measurements. The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"). Under FASB ASC 820, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three level hierarchy for measuring fair value. The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). See Note 8 for additional information.

Legal, Environmental and Other Contingencies. A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company.

Share-Based Payment Arrangements. The Company follows FASB ASC Topic 718, Compensation — Stock Compensation ("FASB ASC 718") which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values. Share-based compensation expense recognized under FASB ASC 718 for the years ended December 31, 2016, 2015 and 2014 was $5.6 million, $4.1 million and $5.5 million, respectively. See Note 6 for additional information.

Conversion of Barrels of Oil to Mcfe of Gas. The Company converts barrels of oil and other liquid hydrocarbons to Mcfe at a ratio of one barrel of oil or liquids to six Mcfe. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or other liquids to an Mcf of natural gas. The sales price of one barrel of oil or liquids has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to a barrel of oil or other liquids.

Recent accounting pronouncements.

Restricted Cash. In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* ("ASU No. 2016-18"). The guidance requires that an explanation is included in the cash flow statement of the change in the total of (1) cash, (2) cash equivalents, and (3) restricted cash or restricted cash equivalents. The ASU also clarifies that transfers between cash, cash equivalents and restricted cash or restricted cash equivalents should not be reported as cash flow activities and requires the nature of the restrictions on cash, cash equivalents, and restricted cash or restricted cash equivalents to be disclosed. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

Statement of Cash Flows. In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)* ("ASU No. 2016-15"). The guidance requires that debt prepayment or debt extinguishment costs, including third-party costs, premiums paid, and other fees paid to lenders, be classified as cash outflows for financing activities. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

Share-Based Payment. In March 2016, the FASB issued Accounting Standards Update ("ASU") 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* ("ASU No. 2016-09") to simplify some of the provisions in stock compensation accounting. The update simplifies the accounting for a stock payment's tax consequences and amends how excess tax benefits and a business's payments to cover the tax bills for the shares' recipients should be classified. The amendments allow companies to estimate the number of stock awards expected to vest and revises the withholding requirements for classifying stock awards as equity. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 with earlier application permitted. The Company is still evaluating the impact of ASU No. 2016-09 on its financial position and results of operations.

Leases. In February 2016, the FASB issued ASU2016-02, *Leases ("ASU No. 2016-02")*. The guidance requires that lessees will be required to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months. The ASU will also require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative information. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 with earlier application permitted. The Company is still evaluating the impact of ASU No. 2016-02 on its financial position and results of operations.

Inventory. In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory* ("ASU No. 2015-11"). Public companies will have to apply the amendments for reporting periods that start after December 15, 2016, including interim periods within those fiscal years. This ASU requires an entity to measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The company does not expect the adoption of ASU No. 2015-11 to have a material impact on its consolidated financial statements.

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03, *Interest — Imputation of Interest (Subtopic 835-30) — Simplifying the Presentation of Debt Issuance Costs.* In August 2015, the FASB issued ASU 2015-15, *Interest — Imputation of Interest (Subtopic 835-30) — Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. These ASUs require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Company adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption resulted in a reclassification that reduced current assets and current maturities of long-term debt by $19.4 million on the Company's Consolidated Balance Sheet at December 31, 2015. A non-cash charge to write-off all of the unamortized debt issuance costs is included in Reorganization items, net at December 31, 2016 as the related debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

Revenue Recognition. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

We are 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, we have dedicated resources to the implementation, completed training of the new ASU's revenue recognition model, and begun contract review and documentation. The primary impacts to the Company of adopting ASU 2014-09 relate to principal versus agent considerations and the use of the entitlements method for oil and natural gas sales, both of which are continuing to be evaluated by the Company.

The Company is required to adopt the new standards in the first quarter of 2018 using one of two application methods: retrospectively to each prior reporting period presented (full retrospective method), or retrospectively with the cumulative effect of initially applying the guidance recognized at the date of initial application (the cumulative catch-up transition method). The Company is currently evaluating the available adoption methods.

Going Concern. In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU No. 2014-15") that requires management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when its plans alleviate substantial doubt about the Company's ability to continue as a going concern. ASU No. 2014-15 becomes effective for annual periods ending after December 15, 2016 and for interim reporting periods thereafter. The adoption of this ASU did not have a material impact on the Company's Consolidated Financial Statements.

Results of Operations — Year Ended December 31, 2016 vs. Year Ended December 31, 2015

	For the year ended December 31,		
	2016	2015	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	264,278	268,954	-2%
Crude oil and condensate (Bbls)	2,912	3,533	-18%
Total production (Mcfe)	281,748	290,149	-3%
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$ 2.31	$ 3.14	-26%
Natural gas ($/Mcf, excluding hedges)	$ 2.31	$ 2.59	-11%
Crude oil and condensate ($/Bbl, incl realized hedges)	$ 38.24	$ 40.31	-5%
Crude oil and condensate ($/Bbl, excluding hedges)	$ 38.24	$ 40.31	-5%
Revenues:			
Natural gas sales	$ 609,756	$ 696,730	-12%
Oil sales	$ 111,335	$ 142,381	-22%
Total operating revenues	$ 721,091	$ 839,111	-14%
Derivatives:			
Realized (loss) on commodity derivatives	$ —	$ 146,801	n/a
Unrealized gain (loss) on commodity derivatives	$ —	$ (104,190)	n/a
Total gain (loss) on commodity derivatives	$ —	$ 42,611	n/a
Operating Costs and Expenses:			
Lease operating expenses	$ 89,134	$ 106,906	-17%
Liquids gathering system operating lease expense	$ 20,686	$ 20,647	0%
Production taxes	$ 69,737	$ 72,774	-4%
Gathering fees	$ 86,809	$ 87,904	-1%
Transportation charges	$ 20,049	$ 83,803	-76%
Depletion, depreciation and amortization	$ 125,121	$ 401,200	-69%
Ceiling test and other impairments	$ —	$3,144,899	-100%
General and administrative expenses	$ 9,179	$ 7,387	24%
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$ 0.32	$ 0.37	-14%
Liquids gathering system operating lease expense	$ 0.07	$ 0.07	0%
Production taxes	$ 0.25	$ 0.25	0%
Gathering fees	$ 0.31	$ 0.30	3%
Transportation charges	$ 0.07	$ 0.29	-76%
Depletion, depreciation and amortization	$ 0.44	$ 1.38	-68%
General and administrative expenses	$ 0.03	$ 0.03	0%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2016, production decreased on a gas equivalent basis to 281.7 Bcfe from 290.1 Bcfe for the same period in 2015. The decrease is primarily attributable to decreased capital investment during the year ended December 31, 2016.

Commodity prices — natural gas. Realized natural gas prices decreased to $2.31 per Mcf during the year ended December 31, 2016 as compared to $2.59 per Mcf during 2015. The Company did not have any open derivative contracts for natural gas production during 2016. During the year ended December 31, 2015, the Company's average price for natural gas was $3.14 per Mcf, including realized gains and losses on commodity derivatives.

Commodity prices — oil. During the year ended December 31, 2016, the average price realization for the Company's oil was $38.24 per barrel compared with $40.31 per barrel during 2015. The Company did not have any open derivative contracts for oil production during 2016 or 2015.

Revenues. The decrease in average oil and natural gas prices and decreased total production resulted in revenues decreasing to $721.1 million for the for the year ended December 31, 2016 as compared to $839.1 million in 2015.

Operating Costs and Expenses:

Lease Operating Expense. Lease operating expenses ("LOE") decreased to $89.1 million for the year ended December 31, 2016 compared to $106.9 million during the same period in 2015 largely related to lower costs due to improved efficiencies. On a unit of production basis, LOE costs decreased to $0.32 per Mcfe at December 31, 2016 compared to $0.37 per Mcfe at December 31, 2015.

Liquids Gathering System Operating Lease Expense. During December 2012, the Company sold a system of liquids gathering pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the Pinedale LGS (the "Pinedale Lease Agreement"). The Pinedale Lease Agreement provides for an initial term of 15 years, and annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. For the year ended December 31, 2016, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $20.7 million, or $0.07 per Mcfe compared with $20.6 million, or $0.07 per Mcfe in 2015.

Production Taxes. During the year ended December 31, 2016, production taxes were $69.7 million compared to $72.8 million during the same period in 2015, or $0.25 per Mcfe in 2016, compared to $0.25 per Mcfe in 2015. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 9.7% of revenues for the year ended 2016 and 8.7% for the same period in 2015. The decrease in production taxes is primarily attributable to decreased oil and natural gas prices during the year December 31, 2016 as compared to the same period in 2015.

Gathering Fees. Gathering fees decreased slightly to $86.8 million for the year ended December 31, 2016 compared to $87.9 million during the same period in 2015. On a per unit basis, gathering fees increased slightly to $0.31 per Mcfe for the year ended December 31, 2016 as compared to $0.30 per Mcfe for the period ended December 31, 2015.

Transportation Charges. Transportation charges decreased to $20.0 million for the year ended December 31, 2016 as compared to $83.8 million for the same period in 2015 primarily as a result of the termination of the Rockies Express contract during the second quarter of 2016. See Note 13 and Note 11 for further discussion of the Rockies Express contract.

Depletion, Depreciation and Amortization. DD&A expenses decreased to $125.1 million during the year ended December 31, 2016 from $401.2 million for the same period in 2015, attributable to a decreased depletion rate on a unit of production basis as a result of the ceiling test impairment during the fourth quarter of 2015. On a unit of production basis, DD&A decreased to $0.44 per Mcfe at December 31, 2016 from $1.38 per Mcfe at December 31, 2015.

Ceiling Test Write-Down. The Company recorded a $3.1 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the period ended December 31, 2015 as a result of ceiling test limitations, which is reflected as ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials. The write-down reduced earnings in the period and will result in lower a DD&A rate in future periods. The Company did not have any write-downs related to the full cost ceiling limitation during the year ended December 31, 2016.

General and Administrative Expenses. General and administrative expenses increased to $9.2 million for the period ended December 31, 2016 compared to $7.4 million for the same period in 2015. The increase in general and administrative expenses is primarily attributable to reversal of certain incentive compensation expense during the year ended December 31, 2015. On a per unit basis, general and administrative expenses remained flat at $0.03 per Mcfe for the year ended December 31, 2016 and 2015.

Other Income and Expenses:

Interest Expense. Interest expense decreased to $66.6 million during the period ended December 31, 2016 compared to $171.9 million during the same period in 2015. No interest has been recognized subsequent to the petition date of April 29, 2016 (See Note 5).

Litigation Expense During the year ended December 31, 2015, the Company recognized litigation expenses of $4.4 million related to the resolution of litigation matters.

Restructuring Expenses. During the year ended December 31, 2016, the Company incurred $7.2 million in costs and fees in connection with its efforts to restructure its debt prior to filing the chapter 11 petitions.

Contract Settlement. Contract settlement of $131.1 million for the year ended December 31, 2016 relates to the contract settlement reached with REX.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2016 and 2015, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the sale of a system of pipelines and central gathering facilities and certain associated real property rights in the Pinedale Anticline in Wyoming during December 2012.

Commodity Derivatives:

Gain on Commodity Derivatives. The Company does not currently have any open commodity derivative contracts. During the year ended December 31, 2015, the Company recognized a gain of $42.6 million related to commodity derivatives. Of this total, the Company recognized $146.8 million related to realized gain during the year ended December 31, 2015. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts. This gain or loss on commodity derivatives also includes a $104.2 million unrealized loss on commodity derivatives at December 31, 2015. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract.

Reorganization Items:

Reorganization Items, Net. Reorganization items, net of $47.5 million for the year ended December 31, 2016 include the contract settlement of $17.35 million related to a settlement reached with Big West Oil, LLC. Reorganization items, net also includes professional fees of $11.8 million and a non-cash charge to write-off all unamortized debt issuance costs totaling $18.7 million related to the unsecured Credit Agreement, the unsecured

Senior Notes issued by Ultra Resources, the unsecured 2018 Senior Notes issued by the Company and the unsecured 2024 Senior Notes issued by the Company as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

Income from Continuing Operations:

Pretax Income. The Company recognized income before income taxes of $55.5 million for the year ended December 31, 2016 compared with a loss of $3.2 billion for the same period in 2015. The increase in earnings is primarily related to the non-cash ceiling test impairment incurred during 2015 and decreased DD&A, reduced interest expense and reduced transportation charges during the year ended December 31, 2016; and partially offset by costs associated with the reorganization and decreased revenues as a result of lower oil and natural gas prices for the year ended December 31, 2016 as compared to the same period in 2015.

Income Taxes. The Company has recorded a valuation allowance against substantially all of its net deferred tax asset balance as of December 31, 2016. Some or all of this valuation allowance may be reversed in future periods against future income.

Net Income. For the year ended December 31, 2016, the Company recognized net income of $56.2 million or $0.36 per diluted share as compared with a net loss of $3.2 billion or ($20.94) per diluted share for the same period in 2015. The increase in earnings is primarily related to the non-cash ceiling test impairment incurred during 2015 and decreased DD&A, reduced interest expense and reduced transportation charges during the year ended December 31, 2016; and partially offset by costs associated with the reorganization and decreased revenues as a result of lower oil and natural gas prices for the year ended December 31, 2016 as compared to the same period in 2015.

Results of Operations — Year Ended December 31, 2015 vs. Year Ended December 31, 2014

	For the year ended December 31,		
	2015	2014	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	268,954	228,517	18%
Crude oil and condensate (Bbls)	3,533	3,409	4%
Total production (Mcfe)	290,149	248,971	17%
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$ 3.14	$ 4.03	-22%
Natural gas ($/Mcf, excluding hedges)	$ 2.59	$ 4.24	-39%
Crude oil and condensate ($/Bbl, incl realized hedges)	$ 40.31	$ 76.47	-47%
Crude oil and condensate ($/Bbl, excluding hedges)	$ 40.31	76.32	-47%
Revenues:			
Natural gas sales	$ 696,730	$ 969,850	-28%
Oil sales	$ 142,381	$ 260,170	-45%
Total operating revenues	$ 839,111	$1,230,020	-32%
Derivatives:			
Realized (loss) gain on commodity derivatives	$ 146,801	$ (47,664)	-408%
Unrealized (loss) on commodity derivatives	$ (104,190)	$ 130,066	-180%
Total (loss) gain on commodity derivatives	$ 42,611	$ 82,402	-48%
Operating Costs and Expenses:			
Lease operating expenses	$ 106,906	$ 96,496	11%
Liquids gathering system operating lease expense	$ 20,647	$ 20,306	2%
Production taxes	$ 72,774	$ 103,898	-30%
Gathering fees	$ 87,904	$ 59,931	47%
Transportation charges	$ 83,803	$ 77,780	8%
Depletion, depreciation and amortization	$ 401,200	$ 292,951	37%
Ceiling test and other impairments	$3,144,899	$ —	n/a
General and administrative expenses	$ 7,387	$ 19,069	-61%
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$ 0.37	$ 0.39	-5%
Liquids gathering system operating lease expense	$ 0.07	$ 0.08	-13%
Production taxes	$ 0.25	$ 0.42	-40%
Gathering fees	$ 0.30	$ 0.24	25%
Transportation charges	$ 0.29	$ 0.31	-6%
Depletion, depreciation and amortization	$ 1.38	$ 1.18	17%
General and administrative expenses	$ 0.03	$ 0.08	-63%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2015, production increased on a gas equivalent basis to 290.1 Bcfe from 249.0 Bcfe for the same period in 2014. The increase is primarily attributable to the SWEPI Transaction in September 2014 and our drilling program, offset by expected production declines. Additionally, on an Mcfe basis, oil production decreased from 8.2% of total production during the year ended December 31, 2014 to 7.3% of total production during the year ended December 31, 2015, primarily as a result of our decision to discontinue drilling in the Uinta Basin in 2015.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, decreased to $3.14 per Mcf during the year ended December 31, 2015 as compared to $4.03 per Mcf during 2014. During the year ended December 31, 2015, the Company's average price for natural gas was $2.59 per Mcf, excluding realized gains and losses on commodity derivatives, as compared to $4.24 per Mcf for the same period in 2014.

Commodity prices — oil. During the year ended December 31, 2015, the average price realization for the Company's oil was $40.31 per barrel compared with $76.47 per barrel during 2014. The Company did not have any open derivative contracts for oil production during 2015. During 2014, the average price realization for the Company's oil was $76.32, including realized gains and losses on commodity derivatives.

Revenues. The decrease in average oil and natural gas prices, excluding the gains and losses on commodity derivatives, offset by increased production from the properties acquired in the SWEPI Transaction and our drilling program resulted in revenues decreasing to $839.1 million for the for the year ended December 31, 2015 as compared to $1.2 billion in 2014.

Operating Costs and Expenses:

Lease Operating Expense. Lease operating expenses ("LOE") increased to $106.9 million for the year ended December 31, 2015 compared to $96.5 million during the same period in 2014 largely related to increased production associated with the SWEPI Transaction and our drilling program. On a unit of production basis, LOE costs decreased to $0.37 per Mcfe at December 31, 2015 compared to $0.39 per Mcfe at December 31, 2014.

Liquids Gathering System Operating Lease Expense. During December 2012, the Company sold a system of liquids gathering pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the Pinedale LGS (the "Pinedale Lease Agreement"). The Pinedale Lease Agreement provides for an initial term of 15 years, and annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. For the year ended December 31, 2015, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $20.6 million, or $0.07 per Mcfe compared with $20.3 million, or $0.08 per Mcfe in 2014.

Production Taxes. During the year ended December 31, 2015, production taxes were $72.8 million compared to $103.9 million during the same period in 2014, or $0.25 per Mcfe, compared to $0.42 per Mcfe. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 8.7% of revenues for the year ended 2015 and 8.4% for the same period in 2014. The decrease in per unit taxes is primarily attributable to decreased natural gas prices, excluding the effects of commodity derivatives, during the year December 31, 2015 as compared to the same period in 2014.

Gathering Fees. Gathering fees increased to $87.9 million for the year ended December 31, 2015 compared to $59.9 million during the same period in 2014 largely related to production increases in Wyoming. On a per unit basis, gathering fees increased to $0.30 per Mcfe for the year ended December 31, 2015 as compared to $0.24 per Mcfe for the period ended December 31, 2014 primarily due to higher gathering rates in Wyoming compared to Pennsylvania.

Transportation Charges. The Company incurred firm transportation charges totaling $83.8 million for the year ended December 31, 2015 as compared to $77.8 million for the same period in 2014 in association with REX transportation charges. Transportation charges increased due to a refund received during the second quarter of 2014 for over collection of tariffs related to Fuel, Loss and Unaccounted-for-Gas applicable to transport on REX's system. On a per unit basis, transportation charges decreased to $0.29 per Mcfe (on total company volumes) for the year ended December 31, 2015 as compared to $0.31 per Mcfe for the same period in 2014 primarily as a result of increased production volumes.

Depletion, Depreciation and Amortization. DD&A expenses increased to $401.2 million during the year ended December 31, 2015 from $293.0 million for the same period in 2014, attributable to a higher depletion rate and increased production. On a unit of production basis, DD&A increased to $1.38 per Mcfe at December 31, 2015 from $1.18 per Mcfe at December 31, 2014 primarily related to decreased reserves as a result of not including PUD reserves in total proved reserve estimates at December 31, 2015 due to uncertainty regarding our ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves.

Ceiling Test Write-Down. The Company recorded a $3.1 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the period ended December 31, 2015 as a result of ceiling test limitations, which is reflected as ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials. The write-down reduced earnings in the period and will result in lower a DD&A rate in future periods. The Company did not have any write-downs related to the full cost ceiling limitation during the prior year ended December 31, 2014.

General and Administrative Expenses. General and administrative expenses decreased to $7.4 million for the period ended December 31, 2015 compared to $19.1 million for the same period in 2014. The decrease in general and administrative expenses is primarily attributable to decreased incentive compensation expense and personnel and overhead charges allocated to the increased wells as a result of the SWEPI Transaction. On a per unit basis, general and administrative expenses decreased to $0.03 per Mcfe for the year ended December 31, 2015 as compared to $0.08 per Mcfe for the year ended December 31, 2014 as a result of decreased costs and increased production.

Other Income and Expenses:

Interest Expense. Interest expense increased to $171.9 million during the period ended December 31, 2015 compared to $126.2 million during the same period in 2014 primarily as a result of higher average borrowings outstanding during the year ended December 31, 2015 and decreased amounts of capitalized interest for the year ended December 31, 2015. For the years ended December 31, 2015 and 2014, the Company capitalized $13.1 million and $20.4 million, respectively, in interest associated with unevaluated oil and gas properties that were excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service.

Litigation Expense During the year ended December 31, 2015, the Company recognized litigation expenses of $4.4 million related to the resolution of litigation matters.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2015 and 2014, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the sale of a system of pipelines and central gathering facilities and certain associated real property rights in the Pinedale Anticline in Wyoming during December 2012.

Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. During the year ended December 31, 2015, the Company recognized a gain of $42.6 million compared with a gain of $82.4 million related to commodity derivatives during the year ended December 31, 2014. Of this total, the Company recognized $146.8 million related to realized gain on commodity derivatives as compared to $47.7 million related to realized loss during the year ended December 31, 2014. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts. This gain or loss on commodity derivatives also includes a $104.2 million unrealized loss on commodity derivatives at December 31, 2015 as compared to a $130.1 million unrealized gain on commodity derivatives at December 31, 2014. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract.

Income from Continuing Operations:

Pretax Income. The Company recognized a loss before income taxes of $3.2 billion for the year ended December 31, 2015 compared with income of $537.0 million for the same period in 2014. The decrease in earnings is primarily related to the non-cash ceiling test impairment and decreased revenues as a result of lower oil and natural gas prices partially offset by increased production for the year ended December 31, 2015 as compared to the same period in 2014.

Income Taxes. The Company has recorded a valuation allowance against substantially all of its net deferred tax asset balance as of December 31, 2015. Some or all of this valuation allowance may be reversed in future periods against future income. The income tax benefit recognized for the year ended December 31, 2015 was $4.4 million compared with an income tax benefit of $5.8 million for the year ended December 31, 2014.

Net Income. For the year ended December 31, 2015, the Company recognized a net loss of $3.2 billion or -$20.94 per diluted share as compared with net income of $542.9 million or $3.51 per diluted share for the same period in 2014. The decrease in earnings is primarily related to the non-cash ceiling test impairment and decreased revenues as a result of lower oil and natural gas prices partially offset by increased production for the year ended December 31, 2015 as compared to the same period in 2014.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Before Filing Under Chapter 11 of the United States Bankruptcy Code

We have historically funded our operations primarily through cash flows from operating activities, borrowings under the Credit Agreement, proceeds from the issuance of debt and proceeds from asset sales. However, future cash flows are subject to a number of variables, and are highly dependent on the prices we receive for oil and natural gas. Oil and natural gas prices declined severely during fiscal year 2015 and declined even further during the first quarter of 2016. The Henry Hub natural gas spot price dropped below $1.65 per MMBtu in March 2016 for the first time in 17 years. Although natural gas prices have improved in recent months, there is still significant volatility in commodity prices and these prices are still lower than the industry has experienced in recent years. These lower commodity prices have negatively impacted revenues, earnings and cash flows, and sustained low oil and natural gas prices will have a material and adverse effect on our liquidity position.

Liquidity After Filing Under Chapter 11 of the United States Bankruptcy Code

As described in Note 1, the filing of the chapter 11 petitions constituted an event of default with respect to our existing debt obligations. However, subject to certain exceptions under the Bankruptcy Code, the filing of the chapter 11 petitions automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the filing of the chapter 11 petitions. Thus, for example, most creditor actions to obtain possession of property from the Debtors, or to create, perfect or enforce any lien against the Debtors' property, or to collect on monies owed or otherwise exercise rights or remedies with respect to a pre-petition claim are enjoined unless and until the Bankruptcy Court lifts the automatic stay.

The Bankruptcy Court has approved payment of certain prepetition obligations, including payments for employee wages, salaries and certain other benefits, customer programs, taxes, utilities, insurance, surety bond premiums as well as payments to possessory lien vendors. Despite the liquidity provided by our existing cash on hand, our ability to maintain normal credit terms with our suppliers may become impaired. We may be required to pay cash in advance to certain vendors and may experience restrictions on the availability of trade credit, which would further reduce our liquidity. If liquidity problems persist, our suppliers could refuse to provide key products and services in the future. In addition, due to the public perception of our financial condition and results of operations, in particular with regard to our potential failure to meet our debt obligations, some vendors could be reluctant to enter into long-term agreements with us.

Although we have lowered our capital budget as compared to 2015, our business remains capital intensive. In addition to the cash requirements necessary to fund ongoing operations, we have incurred significant professional fees and other costs in connection with our chapter 11 proceedings and expect that we will continue to incur significant professional fees and costs throughout our chapter 11 proceedings. The Company believes it has sufficient liquidity, including approximately $401.5 million of cash on hand as of December 31, 2016 and funds generated from ongoing operations, to fund anticipated cash requirements through the chapter 11 proceedings for operating and capital expenditures and for working capital purposes and excluding principal and interest payments on our outstanding debt.

The Company does not intend to seek debtor-in-possession ("DIP") financing at this time. However, given the current level of volatility in the market and the unpredictability of certain costs that could potentially arise in our operations, our liquidity needs could be significantly higher than we currently anticipate. There are no assurances that our current liquidity is sufficient to allow us to satisfy our obligations related to the chapter 11 cases, proceed with the confirmation of a chapter 11 plan of reorganization and emerge from bankruptcy. We can provide no assurance that we will be able to secure additional interim financing sufficient to meet our liquidity needs or, if sufficient funds are available, offered to us on acceptable terms.

Our ability to maintain adequate liquidity through the reorganization process and beyond depends on successful operation of our business, and appropriate management of operating expenses and capital spending. Our anticipated liquidity needs are highly sensitive to changes in each of these and other factors.

Going Concern. The Consolidated Financial Statements included in this Annual Report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The Consolidated Financial Statements do not reflect any adjustments that might result from the outcome of our chapter 11 proceedings. We have significant indebtedness, all of which we have reclassified to liabilities subject to compromise at December 31, 2016. Our level of indebtedness has adversely impacted and is continuing to adversely impact our financial condition. As a result of our financial condition, the defaults under our debt agreements, and the risks and uncertainties surrounding our chapter 11 proceedings, substantial doubt exists that we will be able to continue as a going concern.

Investors should review the disclosures and other information, including the risk factors included in Item 1A.

Capital Expenditures. For the year ended December 31, 2016, total capital expenditures were $269.6 million. During this period, the Company participated in 110 gross (78.4 net) wells in Wyoming that were drilled to total depth and cased. The Company also completed 13 drilled but uncompleted wells in Utah during 2016. No wells were drilled in Utah or Pennsylvania during 2016.

2017 Capital Investment Plan. For 2017, our capital expenditures are expected to be approximately $500.0 million. We expect to fund these capital expenditures through cash flows from operations and cash on hand. We expect to allocate nearly all of the budget to development activities in our Pinedale field.

Other Developments. Trading in the Company's common stock on the NYSE was suspended on May 3, 2016 and the common stock was delisted. The common stock of the Company currently trades on the OTC Pink marketplace under the symbol "UPLMQ".

Ultra Resources, Inc.

Bank indebtedness. Ultra Resources, Inc. ("Ultra Resources"), a wholly owned subsidiary of the Company, is a party to the Credit Agreement. Ultra Resources' obligations under the Credit Agreement are guaranteed by the Company and UP Energy Corporation, a wholly owned subsidiary of the Company.

Ultra Resources' filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated its obligations under the Credit Agreement. Other events of default are also present with respect to the Credit Agreement, including a failure to make interest payments and, as described below, a failure to deliver annual audited consolidated financial statements without a going concern qualification, a failure to meet the minimum PV-9 ratio covenant and a failure to comply with the consolidated leverage covenant in the Credit Agreement at the end of the first quarter of 2016. The Credit Agreement provides that upon the acceleration of Ultra Resources' obligations under the Credit Agreement, the outstanding balance of loans extended under the Credit Agreement comes due, unpaid interest accrued as of the time of the acceleration comes due, and any fees or other obligations of the borrower come due. Under the Bankruptcy Code, the creditors under the Credit Agreement are stayed from taking any action against Ultra Resources or any of the other Debtors as a result of the default.

Prior to April 29, 2016, loans under the Credit Agreement bore interest, at the borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus a margin based on a grid of the borrower's consolidated leverage ratio, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the borrower's consolidated leverage ratio.

The Credit Agreement requires us to deliver annual audited, consolidated financial statements for the Company without a "going concern" or like qualification or explanation. On March 15, 2016, we delivered an audit report with respect to the financial statements in our 2015 Annual Report on Form 10-K that included an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern."

The Credit Agreement contains a consolidated leverage covenant, pursuant to which Ultra Resources is required to maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0. Based on Ultra Resources' EBITDAX for the trailing four fiscal quarters ended March 31, 2016, we were not in compliance with this consolidated leverage covenant at March 31, 2016 (the ratio was 4.6 times at March 31, 2016).

The Credit Agreement contains a PV-9 covenant, pursuant to which Ultra Resources is required to maintain a minimum ratio of the discounted net present value of its oil and gas properties to its total funded consolidated debt of 1.5 times. We were required to report whether we were in compliance with this covenant on April 1, 2016. Based on the PV-9 of its oil and gas properties at December 31, 2015, Ultra Resources failed to comply with the PV-9 ratio covenant under the Credit Agreement (the ratio was 0.9 times at December 31, 2015).

Senior Notes. Ultra Resources has outstanding $1.46 billion of Senior Notes which were issued pursuant to a certain Master Note Purchase Agreement dated as of March 6, 2008 (as amended, supplemented or otherwise modified, the "MNPA"). The Ultra Resources' Senior Notes rank pari passu with the Credit Agreement. Payment of the Senior Notes is guaranteed by the Company and by UP Energy Corporation. The Ultra Resources' Senior Notes are subject to representations, warranties, covenants and events of default similar to those in the Credit Agreement.

Ultra Resources' filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated its obligations under the MNPA and the Senior Notes. Other events of default are also present with respect to the MNPA, including a failure to comply with the consolidated leverage covenant at the end of the first quarter of 2016 and a failure to make principal and interest payments due under the Ultra Resources' Senior

Notes. The MNPA provides that upon the acceleration of Ultra Resources' obligations under the MNPA and the Senior Notes, among other matters, the Senior Notes are deemed to have matured, the unpaid principal balance of the Senior Notes comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable Make-Whole Amount (as determined pursuant to the MNPA) comes due. Under the Bankruptcy Code, the creditors under the Senior Notes are stayed from taking any action against Ultra Resources or any of the other the Debtors as a result of the default.

The MNPA contains a consolidated leverage covenant, pursuant to which Ultra Resources is required to maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0. Based on Ultra Resources' EBITDAX for the trailing four fiscal quarters ended March 31, 2016, we were not in compliance with this consolidated leverage covenant at March 31, 2016 (the ratio was 4.6 times at March 31, 2016).

On March 1, 2016, we failed to make an interest payment of approximately $40.0 million and a principal payment of $62.0 million, each of which was due March 1, 2016 under the terms of the Ultra Resources' Senior Notes. We entered into a forbearance agreement related to the failure to make these payments with the holders of the Ultra Resources' Senior Notes, and we filed the chapter 11 petitions without making the payments before the forbearance period expired.

Interest Expense. No interest expense has been recognized with respect to the Credit Agreement or the Ultra Resources' Senior Notes subsequent to the Petition Date.

Ultra Petroleum Corp. Senior Notes

The Company's filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated the Company's obligations under the 2024 Notes and the 2018 Notes (defined below). Additionally, other events of default, including cross-defaults, are present due to the failure to make interest payments and other matters. Under the indentures pursuant to which the 2024 Notes and the 2018 Notes, respectively, were issued, upon the acceleration of the Company's obligations under the 2024 Notes and the 2018 Notes, among other matters, the 2024 Notes and the 2018 Notes, respectively, are deemed to have matured, the unpaid principal balance of the 2024 Notes and the 2018 Notes, respectively, comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable premiums (as determined pursuant to the indentures) comes due. Under the Bankruptcy Code, the creditors under the 2024 Notes and the 2018 Notes are stayed from taking any action against the Debtors as a result of the default.

Senior Notes due 2024: On September 18, 2014, the Company issued $850.0 million of 6.125% Senior Notes due 2024 ("2024 Notes"). The 2024 Notes are general, unsecured senior obligations of the Company and mature on October 1, 2024. The 2024 Notes rank equally in right of payment to all existing and future senior indebtedness of the Company and effectively rank junior to all future secured indebtedness of the Company (to the extent of the value of the collateral securing such indebtedness). The 2024 Notes are not guaranteed by the Company's subsidiaries and, as a result, are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. The 2024 Notes are subject to covenants that restrict the Company's ability to incur indebtedness, make distributions and other restricted payments, grant liens, use the proceeds of asset sales, make investments and engage in affiliate transactions.

Interest due under the 2024 Notes is payable each April 1 and October 1. On April 1, 2016, we elected to defer making an interest payment on the 2024 Notes of approximately $26.0 million due April 1, 2016. The indenture governing the 2024 Notes provides a 30-day grace period for us to make this interest payment. We did not make this interest payment before the end of the grace period, which resulted in an event of default under the indenture governing the 2024 Notes.

Senior Notes due 2018: On December 12, 2013, the Company issued $450.0 million of 5.75% Senior Notes due 2018 ("2018 Notes"). The 2018 Notes are general, unsecured senior obligations of the Company and mature on December 15, 2018. The 2018 Notes rank equally in right of payment to all existing and future senior indebtedness of the Company and effectively rank junior to all future secured indebtedness of the Company (to the extent of the value of the collateral securing such indebtedness). The 2018 Notes are not guaranteed by the Company's subsidiaries and, as a result, are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. The 2018 Notes are subject to covenants that restrict the Company's ability to incur indebtedness, make distributions and other restricted payments, grant liens, use the proceeds of asset sales, make investments and engage in affiliate transactions. Interest due under the 2018 Notes is payable each June 15 and December 15.

The Company's filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated the Company's obligations under the 2024 Notes and the 2018 Notes. Additionally, other events of default, including cross-defaults resulting from the acceleration of indebtedness outstanding under the Credit Agreement and the Ultra Resources' Senior Notes, are present due to the failure to make interest payments and other matters. Under the Bankruptcy Code, the creditors under the 2024 Notes and the 2018 Notes are stayed from taking any action against the Debtors as a result of the bankruptcy filing.

Interest Expense. No interest expense has been recognized with respect to the 2018 Notes or 2024 Notes subsequent to the Petition Date.

Cash flows provided by (used in):

Operating Activities. During the year ended December 31, 2016, net cash provided by operating activities was $307.6 million, a 40% decrease from $515.5 million for the same period in 2015. The decrease in net cash provided by operating activities was largely attributable to decreased revenues as a result of decreased oil and natural gas price realizations and partially offset by a decrease in post-petition interest expense during the year ended December 31, 2016 as compared to the same period in 2015 and net changes in working capital.

Investing Activities. During the year ended December 31, 2016, net cash used in investing activities was $278.9 million as compared to $512.8 million for the same period in 2015. The decrease in net cash used in investing activities is largely related to decreased capital investments associated with the Company's drilling activities in 2016 as compared to 2015.

Financing Activities. During the year ended December 31, 2016, net cash provided by financing activities was $368.6 million as compared to net cash used in financing activities of $7.6 million for the same period in 2015. The change in cash provided by net financing activities is primarily due to increased borrowings during 2016, primarily related to drawings under the Credit Agreement.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2016.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2016:

	Payments Due by period:				
	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
	(Amounts in thousands of U.S. dollars)				
Long-term debt (See Note 5)	$3,759,000	$3,759,000	$ —	$ —	$ —
Scheduled interest obligations (See Note 5)	—	—	—	—	—
Operating lease — Liquids Gathering System	229,934	20,903	41,806	41,806	125,419
Office space lease	6,570	1,286	2,375	2,327	582
Total contractual obligations	$3,995,504	$3,781,189	$ 44,181	$ 44,133	$126,001

Outstanding debt. On April 29, 2016, to restructure their respective obligations and capital structures, the Company and each of its direct and indirect wholly owned subsidiaries (collectively, the "Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. See Note 1.

The chapter 11 filings by the Company and its various subsidiaries, including Ultra Resources, constituted events of default under the Company's debt agreements. On or around September 1, 2016, many of the holders of this indebtedness filed proofs of claim with the Bankruptcy Court, asserting claims for the outstanding balance of the indebtedness, unpaid interest that had accrued by the petition dates, interest that has accrued since the petition dates (including interest at the default rates under the debt agreements), make-whole amounts, and other fees and obligations under the debt agreements. On December 29, 2016, holders of certain Senior Notes (as defined below) filed a complaint initiating an adversary proceeding against us in our chapter 11 cases. In the complaint, among other matters, the noteholders allege that there is a make-whole amount due under the Senior Notes as a result of our filing the chapter 11 cases, which they assert is "no less than $200,725,869, exclusive of any interest thereon." On January 13, 2017, holders of certain other Senior Notes intervened to join the adversary proceeding as plaintiffs. On January 30, 2017, we filed a motion to dismiss the complaint. On February 10, 2017, both noteholder groups objected to our motion to dismiss. On February 13, 2017, the Court set a briefing schedule and a hearing date for April 20, 2017 for resolution of the make-whole and interest claims. At this time, we are not able to determine the likelihood or range of amounts attributable to claims for postpetition interest, make-whole amounts, or other fees and obligations under the debt agreements. We anticipate these claims will be resolved during our chapter 11 proceedings, although it is possible resolution of some of these matters could occur after we emerge from chapter 11.

Ultra Resources' filing of the chapter 11 petitions constituted an event of default that accelerated its obligations under the Credit Agreement. Other events of default are also present with respect to the Credit Agreement, including a failure to make interest payments and, as described in Note 5, a failure to deliver annual audited consolidated financial statements without a going concern qualification, a failure to meet the minimum PV-9 ratio covenant and a failure to comply with the consolidated leverage covenant in the Credit Agreement at the end of the first quarter of 2016. The Credit Agreement provides that upon the acceleration of Ultra Resources' obligations under the Credit Agreement, the outstanding balance of loans extended under the Credit Agreement comes due, unpaid interest accrued as of the time of the acceleration comes due, and any fees or other obligations of the borrower come due. Under the Bankruptcy Code, the creditors under the Credit Agreement are stayed from taking any action against Ultra Resources or any of the other Debtors as a result of the default.

Ultra Resources has outstanding $1.46 billion of senior notes ("Senior Notes") which were issued pursuant to a certain Master Note Purchase Agreement dated as of March 6, 2008 (as amended, supplemented or otherwise modified, the "MNPA"). Ultra Resources' filing of the chapter 11 petitions constituted an event of default that accelerated its obligations under the MNPA and the Senior Notes. Other events of default are also present with respect to the MNPA, including a failure to comply with the consolidated leverage covenant at the end of the first quarter of 2016 and a failure to make principal and interest payments due under the Ultra Resources' Senior Notes. The MNPA provides that upon the acceleration of Ultra Resources' obligations under the MNPA and the Senior Notes, among other matters, the Senior Notes are deemed to have matured, the unpaid principal balance of the Senior Notes comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable make-whole amount (as determined pursuant to the MNPA) comes due. Under the Bankruptcy Code, the creditors under the Senior Notes are stayed from taking any action against Ultra Resources or any of the other the Debtors as a result of the default.

The Company's filing of the chapter 11 petitions constituted an event of default that accelerated the Company's obligations under the 2024 Notes and the 2018 Notes. Additionally, other events of default, including cross-defaults, are present due to the failure to make interest payments and other matters. Under the indentures pursuant to which the 2024 Notes and the 2018 Notes, respectively, were issued, upon the acceleration of the Company's obligations under the 2024 Notes and the 2018 Notes, among other matters, the 2024 Notes and the

2018 Notes, respectively, are deemed to have matured, the unpaid principal balance of the 2024 Notes and the 2018 Notes, respectively, comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable premiums (as determined pursuant to the indentures) comes due. Under the Bankruptcy Code, the creditors under the 2024 Notes and the 2018 Notes are stayed from taking any action against the Debtors as a result of the default.

Scheduled interest obligations. No interest expense has been recognized with respect to the Credit Agreement, the Ultra Resources' Senior Notes, the 2018 Notes or the 2024 Notes subsequent to the Petition Date. Due to the ongoing chapter 11 proceedings, these amounts cannot be reasonably estimated.

Transportation contract. Between 2009 and early 2016, the Company was a party to agreements that provided the Company with firm transportation services on the Rockies Express Pipeline, including a Capacity Release Agreement, dated March 5, 2009, with Sempra Rockies Marketing, LLC ("Sempra"), and a Firm Transportation Negotiated Rate Agreement No. 553082, dated June 5, 2008, with Rockies Express Pipeline, LLC ("REX"). During March and April 2016, both Sempra and REX delivered notices to the Company asserting that these agreements were terminated as a result of defaults by the Company. Both Sempra and REX filed proofs of claim in connection with our on-going chapter 11 proceedings. With respect to the proof of claim filed by REX, on January 12, 2017, REX and the Company entered into a settlement agreement resolving all of REX's prepetition claims against the Company. Please see the discussion of these matters in the Commitments and Contingencies section of this Report on Form 10-K for additional information. In connection with the settlement of REX's proof of claim, the Company agreed to enter into a new first transportation agreement pursuant to which the Company will have firm transportation capacity of 200,000 Dekatherms per day on the Rockies Express Pipeline, beginning December 1, 2019 and extending for a term expiring December 31, 2026. This new agreement will provide the Company with the opportunity to transport a portion of its natural gas production away from its properties in Wyoming to capture improved basis differentials available at sales points along the Rockies Express Pipeline, if any. Please see Note 13 for further details.

Operating lease. During December 2012, the Company sold its system of pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming and entered into a long-term, triple net lease agreement (the "Pinedale Operating Lease Agreement") relating to the use of the Pinedale LGS. The Pinedale Operating Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Operating Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index, which is 1.05% at January 1, 2017) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease.

On November 11, 2016, the Company reached an agreement with the owner of the Pinedale LGS whereby the owner agreed to withdraw its damages claims in exchange for the Company's subsidiary assuming the Pinedale Operating Lease Agreement with no cost to cure.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease. The Company maintains office space in Colorado, Texas, Wyoming and Utah with total remaining commitments for office leases of $6.6 million at December 31, 2016.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. As a result of its hedging activities, the Company may realize prices that are less than or greater than the spot prices that it would have received otherwise.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

Commodity Derivative Contracts: At December 31, 2016, the Company had no open commodity derivative contracts to manage price risk on a portion of its production.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2016, 2015 and 2014:

	For the Year Ended December 31,		
Commodity Derivatives (000's):	**2016**	**2015**	**2014**
Realized gain (loss) on commodity derivatives-natural gas(1)	$ —	$ 146,801	$ (48,170)
Realized gain (loss) on commodity derivatives-crude oil(1)	—	—	506
Unrealized gain (loss) on commodity derivatives(1)	—	(104,190)	130,066
Total gain (loss) on commodity derivatives	$ —	$ 42,611	$ 82,402

(1) Included in gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

Item 8. ***Financial Statements and Supplementary Data.***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession)

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2016. 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 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in the notes to the consolidated financial statements, Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) filed for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code on April 29, 2016. This condition raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters also are described in the notes to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Ultra Petroleum Corp. and subsidiaries' (Debtor-in-Possession) internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 22, 2017, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession)

We have audited Ultra Petroleum Corp. and subsidiaries' (Debtor-in-Possession) internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Ultra Petroleum Corp. and subsidiaries' (Debtor-in-Possession) management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2016, of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) and our report dated February 22, 2017, expressed an unqualified opinion thereon that included an explanatory paragraph regarding Ultra Petroleum Corp and subsidiaries' (Debtor-in-Possession) ability to continue as a going concern.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2017

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2016	2015	2014
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 609,756	$ 696,730	$ 969,850
Oil sales	111,335	142,381	260,170
Total operating revenues	721,091	839,111	1,230,020
Expenses:			
Lease operating expenses	89,134	106,906	96,496
Liquids gathering system operating lease expense	20,686	20,647	20,306
Production taxes	69,737	72,774	103,898
Gathering fees	86,809	87,904	59,931
Transportation charges	20,049	83,803	77,780
Depletion, depreciation and amortization	125,121	401,200	292,951
Ceiling test and other impairments	—	3,144,899	—
General and administrative	9,179	7,387	19,069
Total operating expenses	420,715	3,925,520	670,431
Operating income (loss)	300,376	(3,086,409)	559,589
Other income (expense), net:			
Interest expense (excludes contractual interest expense of $141.5 million for the year ended December 31, 2016)	(66,565)	(171,918)	(126,157)
Gain on commodity derivatives	—	42,611	82,402
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553
Litigation expense	—	(4,401)	—
Restructuring expenses	(7,176)	—	—
Contract settlement	(131,106)	—	—
Gain on sale of property	—	—	8,022
Other (expense) income, net	(3,082)	(2,060)	2,618
Total other (expense) income, net	(197,376)	(125,215)	(22,562)
Reorganization items, net	(47,503)	—	—
Income (loss) before income tax benefit	55,497	(3,211,624)	537,027
Income tax benefit	(654)	(4,404)	(5,824)
Net income (loss)	$ 56,151	$(3,207,220)	$ 542,851
Basic Earnings (Loss) per Share:			
Net income (loss) per common share — basic	$ 0.37	$ (20.94)	$ 3.54
Fully Diluted Earnings (Loss) per Share:			
Net income (loss) per common share — fully diluted	$ 0.36	$ (20.94)	$ 3.51
Weighted average common shares outstanding — basic	153,378	153,192	153,136
Weighted average common shares outstanding — fully diluted	154,081	153,192	154,694

Approved on behalf of the Board:

/s/ Michael D. Watford	/s/ Michael J. Keeffe
Chairman of the Board, Chief Executive Officer and President	Director

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 401,478	$ 4,143
Restricted cash	3,571	115
Oil and gas revenue receivable	79,179	61,881
Joint interest billing and other receivables	10,781	11,356
Income tax receivable	2,099	5,150
Inventory	4,906	4,269
Deposits and retainers	13,359	—
Other current assets	6,020	4,300
Total current assets	521,393	91,214
Oil and gas properties, net, using the full cost method of accounting:		
Proven	1,010,466	851,145
Property, plant and equipment	7,695	8,844
Deferred income taxes	—	1
Other	1,374	835
Total assets	$ 1,540,928	$ 952,039
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 28,171	$ 93,415
Accrued liabilities	53,348	72,428
Production taxes payable	44,329	52,273
Current portion of long-term debt	—	3,370,553
Interest payable	—	42,657
Capital cost accrual	12,360	20,571
Total current liabilities	138,208	3,651,897
Deferred gain on sale of liquids gathering system	115,742	126,295
Other long-term obligations	177,088	165,784
Total liabilities not subject to compromise	431,038	3,943,976
Liabilities subject to compromise	4,038,041	—
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding shares — 153,418,041 and 153,255,989, at December 31, 2016 and 2015, respectively	510,063	502,050
Treasury stock	(49)	(176)
Retained loss	(3,438,165)	(3,493,811)
Total shareholders' deficit	(2,928,151)	(2,991,937)
Total liabilities and shareholders' equity	$ 1,540,928	$ 952,039

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Amounts in thousands of U.S. dollars, except share data)

	Shares Issued and Outstanding	Common Stock	Retained Loss	Treasury Stock	Total Shareholders' (Deficit) Equity
Balances at December 31, 2013	152,991	$487,273	$ (816,802)	$(1,961)	$ (331,490)
Stock options exercised	43	770	—	—	770
Employee stock plan grants	298	700	—	—	700
Shares re-issued from treasury	—	(770)	(1,450)	2,220	—
Shares repurchased	(332)	—	—	(6,472)	(6,472)
Net share settlements	(104)	—	(2,639)	—	(2,639)
Fair value of employee stock plan grants	—	7,940	—	—	7,940
Net income	—	—	542,851	—	542,851
Balances at December 31, 2014	152,896	$495,913	$ (278,040)	$(6,213)	$ 211,660
Employee stock plan grants	526	700	—	—	700
Shares re-issued from treasury	—	—	(6,037)	6,037	—
Net share settlements	(166)	—	(2,514)	—	(2,514)
Fair value of employee stock plan grants	—	5,437	—	—	5,437
Net (loss)	—	—	(3,207,220)	—	(3,207,220)
Balances at December 31, 2015	153,256	$502,050	$(3,493,811)	$ (176)	$(2,991,937)
Employee stock plan grants	279	—	—	—	—
Shares re-issued from treasury	—	—	(127)	127	—
Net share settlements	(117)	—	(379)	—	(379)
Fair value of employee stock plan grants	—	8,014	—	—	8,014
Net income	—	—	56,151	—	56,151
Balances at December 31, 2016	153,418	$510,064	$(3,438,166)	$ (49)	$(2,928,151)

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2016	2015	2014
Cash provided by (used in):	(Amounts in thousands of U.S. dollars)		
Operating activities:			
Net income (loss) for the period	$ 56,151	$ (3,207,220)	$ 542,851
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depletion, depreciation and amortization	125,121	401,200	292,951
Ceiling test and other impairments	—	3,144,899	—
Deferred and current non-cash income taxes	1	(990)	995
Unrealized (gain) loss on commodity derivatives	—	104,190	(130,066)
Deferred gain on sale of liquids gathering system	(10,553)	(10,553)	(10,553)
Gain on sale of property	—	—	(8,022)
Stock compensation	5,562	4,128	5,467
Non-cash reorganization items, net	42,523	—	—
Other	6,870	9,217	4,569
Net changes in operating assets and liabilities:			
Restricted cash	(3,456)	2	2
Accounts receivable	(19,635)	65,132	(43,116)
Other current assets	(15,647)	(20,106)	(1,920)
Other non-current assets	(539)	21,112	284
Accounts payable	(63,924)	13,815	28,696
Accrued liabilities	133,144	1,655	(5,938)
Production taxes payable	(7,944)	(3,312)	15,115
Interest payable	57,117	(3,441)	14,233
Other long-term obligations	276	(5,770)	6,427
Current taxes payable/receivable	2,547	1,580	609
Net cash provided by operating activities	307,614	515,538	712,584
Investing Activities:			
Acquisition of oil and gas properties	—	3,964	(891,075)
Oil and gas property expenditures	(269,314)	(494,025)	(599,913)
Gathering system expenditures	—	—	(6,842)
Proceeds from sale of property	—	—	27,944
Change in capital cost accrual	(8,134)	(25,380)	(125,577)
Inventory	(1,123)	3,235	175
Purchase of property, plant and equipment	(329)	(551)	(5,455)
Net cash used in investing activities	(278,900)	(512,757)	(1,600,743)
Financing activities:			
Borrowings on long-term debt	369,000	1,165,000	1,095,000
Payments on long-term debt	—	(1,153,000)	(1,037,000)
Proceeds from issuance of Senior Notes	—	—	850,000
Deferred financing costs	—	6	(13,245)
Repurchased shares/net share settlements	(379)	(2,514)	(9,111)
Payment of contingent consideration	—	(17,049)	—
Proceeds from exercise of options	—	—	770
Net cash provided by (used in) financing activities	368,621	(7,557)	886,414
Increase/(Decrease) in cash during the period	397,335	(4,776)	(1,745)
Cash and cash equivalents, beginning of period	4,143	8,919	10,664
Cash and cash equivalents, end of period	$ 401,478	$ 4,143	$ 8,919
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 4,793	$ 169,867	$ 108,889
Income taxes	$ 94	$ —	$ 1,752
Non-cash investing activities — oil and gas properties	$ —	$ —	$ 20,000

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(All amounts in this Report on Form 10-K are expressed in thousands of U.S. dollars (except per share data), unless otherwise noted).

DESCRIPTION OF THE BUSINESS:

Ultra Petroleum Corp. (the “Company”) is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company is incorporated under the laws of Yukon, Canada. The Company’s principal business activities are developing its long-life natural gas reserves in the Green River Basin of Wyoming – the Pinedale and Jonah fields, its oil reserves in the Uinta Basin in Utah and its natural gas reserves in the Appalachian Basin of Pennsylvania.

Chapter 11 Proceedings, Ability to Continue as a Going Concern

Chapter 11 Proceedings

On April 29, 2016 (the “Petition Date”), to restructure their respective obligations and capital structures, the Company and each of its direct and indirect wholly owned subsidiaries (collectively, the “Ultra Entities” or “Debtors”) filed voluntary petitions under chapter 11 of title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of Texas (the “Bankruptcy Court”). The Debtors’ chapter 11 cases are being jointly administered for procedural purposes under the caption In re Ultra Petroleum Corp., et al, Case No. 16-32202 (MI) (Bankr. S.D. Tex.). Information about our chapter 11 cases is available at our website (www.ultrapetroleum.com) and also at a website maintained by our claims agent, Epiq Systems (http://dm.epiq11.com/UPT/Docket).

We are currently operating our business as a debtor-in-possession in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. After we filed our chapter 11 petitions, the Bankruptcy Court granted certain relief we requested enabling us to conduct our business activities in the ordinary course, including, among other things and subject to the terms and conditions of such orders, authorizing us to pay employee wages and benefits, pay taxes and certain governmental fees and charges, continue to operate our cash management system in the ordinary course, remit funds we hold from time to time for the benefit of third parties (such as royalty owners), and pay the prepetition claims of certain of our vendors that hold liens under applicable non-bankruptcy law. For goods and services provided following the Petition Date, we intend to pay vendors in full under normal terms.

Subject to certain exceptions provided for in section 362 of the Bankruptcy Code, all judicial and administrative proceedings against us or our property were automatically enjoined, or stayed, as of the Petition Date. In addition, the filing of new judicial or administrative actions against us or our property for claims arising prior to the date on which our chapter 11 cases were filed were automatically enjoined. This prohibits, for example, our lenders or noteholders from pursuing claims for defaults under our debt agreements and our contract counterparties from pursuing claims for defaults under our contracts. Accordingly, unless the Bankruptcy Court agrees to lift the automatic stay, all of our prepetition liabilities and obligations should be settled or compromised under the Bankruptcy Code as part of our chapter 11 proceedings.

Our operations and ability to execute our business remain subject to the risks and uncertainties described in Item 1A, “Risk Factors”. In addition, our assets, liabilities, including our capital structure, shareholders, officers and/or directors could change materially because of our chapter 11 cases. In addition, the description of our operations, properties and capital plans included in this Annual Report on Form 10-K may not accurately reflect our operations, properties and capital plans after we emerge from chapter 11.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Creditors' Committees – Appointment & Formation

On May 5, 2016, the United States Trustee for the Southern District of Texas appointed an official committee for unsecured creditors of all of the Debtors (the "UCC"). On September 26, 2016, the United States Trustee for the Southern District of Texas filed a Notice of Reconstitution of the UCC. In addition, certain other stakeholders have organized for purposes of participating in the Debtors' chapter 11 cases: (i) on June 8, 2016, an informal ad hoc committee of unsecured creditors of our subsidiary, Ultra Resources, Inc. ("Ultra Resources"), notified the Bankruptcy Court it had formed and identified its members, most of which are distressed debt investors and/or hedge funds; (ii) on June 13, 2016, an informal ad hoc committee of the holders of senior notes issued by the Company notified the Bankruptcy Court it had formed and identified its members; (iii) on July 20, 2016, an informal ad hoc committee of shareholders of the Company notified the Bankruptcy Court it had formed and identified its members; and (iv) on January 6, 2017, an informal ad hoc committee of unsecured creditors of our subsidiary, Ultra Resources, notified the Bankruptcy Court it had formed and identified its members, most of which are insurance companies. We expect each of the committees to be involved in our chapter 11 cases, and any disagreements with any of the committees may extend our chapter 11 cases, increase the cost of our chapter 11 cases, and/or delay our emergence from chapter 11.

Exclusivity

The Bankruptcy Code provides chapter 11 debtors-in-possession with the exclusive right to file a plan of reorganization under chapter 11 through a period of time specified in the Bankruptcy Code, which period may be extended by the Bankruptcy Court. On July 27, 2016, we filed a motion seeking an extension of the exclusive chapter 11 plan filing period. At a hearing conducted on August 25, 2016, the Bankruptcy Court extended our exclusive right to file a plan of reorganization under chapter 11 through and including March 1, 2017, and to solicit acceptances of such plan through and including May 1, 2017, subject to our producing and delivering a long-term business plan prior to December 1, 2016. The long-term business plan was provided prior to December 1, 2016, and, pursuant to a Stipulation Regarding Order Extending Exclusivity signed by the Bankruptcy Court, we satisfied the condition (with the effect that our exclusive right to file a reorganization plan now continues until and including March 1, 2017, and our exclusive right to solicit acceptances of such a plan continues until and including May 1, 2017). On February 1, 2017, we filed a motion seeking an extension of the exclusive chapter 11 plan filing period through June 29, 2017 and the exclusive right to solicit acceptances of a chapter 11 plan through August 29, 2017. On February 17, 2017, we filed a revised proposed form of order to the motion seeking an extension of the exclusive chapter 11 plan filing period through April 15, 2017 and the exclusive right to solicit acceptances of a chapter 11 plan through June 15, 2017.

Plan Support Agreement, Rights Offering, Backstop Commitment Agreement and Exit Financing Commitment Letter

On November 21, 2016, each of the Ultra Entities entered into a Plan Support Agreement ("PSA") with (i) holders of at least 66.67% of the principal amount of the Company's outstanding 5.750% Senior Notes due 2018 and 6.125% Senior Notes due 2024 and (ii) shareholders who own at least a majority of the Company's outstanding common stock or the economic interests therein (collectively, the "Plan Support Parties") and a Backstop Commitment Agreement ("BCA") with a subset thereof (collectively, the "Commitment Parties").

Plan Support Agreement: The PSA sets forth the terms and conditions pursuant to which the Ultra Entities and the Commitment Parties have agreed to seek and support a joint plan of reorganization at an aggregate plan value of $6.25 billion, $6.0 billion, or $5.5 billion, depending on commodity prices, for the Ultra Entities which will successfully complete the Reorganization Proceedings (collectively, the "Plan"). Under the

Plan, the total enterprise value of the Ultra Entities will be $6.0 billion (the “Plan Value”); provided, that if the average closing price of the 12-month forward Henry Hub natural gas strip price during the seven (7) trading days preceding the commencement of the Rights Offering solicitation is: (i) greater than $3.65/MMBtu, the Plan Value will be $6.25 billion; or (ii) less than $3.25/MMBtu, the Plan Value will be $5.5 billion.

Among other matters, the Plan provides for a comprehensive restructuring of all allowable claims against and interests in the Ultra Entities, including the conversion of the outstanding unsecured senior notes issued by the Company (“HoldCo Notes” and, the holders thereof, “HoldCo Noteholders”) to newly-issued shares of common stock in the Company, the exchange of the outstanding unsecured senior notes issued by UPL’s subsidiary Ultra Resources for a combination of new unsecured notes issued by Ultra Resources and cash, the payment in full of all other allowed claims against the Ultra Debtors in cash, and the distribution to each owner of common stock in the Company as of the Plan’s record date (“HoldCo Equityholders”) of such owner’s pro rata share of the new UPL common stock and the right to participate in the Rights Offering (as described below).

The PSA provides certain milestones for the restructuring, which the Company is required to use commercially reasonable efforts to satisfy. Failure of the Company to satisfy certain milestones, including (i) entry of an order approving the Debtors’ entry into the BCA by January 20, 2017 and (ii) consummation of the Plan by April 15, 2017 would provide the Plan Support Parties a termination right under the PSA.

On February 9, 2017, the Company entered into the First Amendment to the Plan Support Agreement (the “PSA Amendment”) with the Plan Support Parties party thereto. Pursuant to the PSA Amendment, the Required Consenting Parties agreed that the Plan Term Sheet, as modified to accord with the treatment of OpCo Funded Debt Claims and General Unsecured Claims under the Second Amended Plan, is reasonably satisfactory to such parties (as such terms are defined in the Plan Support Agreement).

On February 13, 2017, the Court signed an order approving our Disclosure Statement. On February 21, 2017, the Court signed an amended order approving our Disclosure Statement. The amended order: (1) approves the adequacy of our Disclosure Statement, (2) approves the solicitation and notice procedures related to confirmation of our plan of reorganization, (3) approves the forms of ballots and notices related thereto, (4) approves the rights offering procedures and matters related thereto, (5) schedules certain dates related to our plan confirmation process and Rights Offering, and (6) grants related relief. With respect to the Rights Offering, the amended order defines the “Subscription Commencement Date” as February 21, 2017. Accordingly, as will be reflected in the materials to be distributed in connection with the Rights Offering, the Plan Value under the PSA is $6.0 billion.

Rights Offering: In accordance with the Plan, the BCA and the Rights Offering procedures submitted by the Company in connection with the Plan, the Company will offer eligible debt and equity holders, including the Commitment Parties, the right to purchase shares of new common stock in the Company upon effectiveness of the Plan for an aggregate purchase price of $580.0 million. The Rights Offering will consist of the following offerings:

- HoldCo Noteholders shall be granted rights (the “HoldCo Noteholder Rights Offering”) entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the “HoldCo Noteholder Rights Offering Shares”), which HoldCo Noteholder Rights Offering Shares, collectively, will reflect an aggregate purchase price of $435.0 million.
- HoldCo Equityholders shall be granted rights (the “HoldCo Equityholder Rights Offering”) entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the “HoldCo Equityholder Rights Offering Shares” and, together with the HoldCo

Noteholder Rights Offering Shares, the "Rights Offering Shares"), which HoldCo Equityholder Rights Offering Shares, collectively, will reflect an aggregate purchase price of $145.0 million.

Backstop Commitment Agreement: Under the BCA, the Commitment Parties have agreed to purchase the HoldCo Noteholder Rights Offering Shares and the HoldCo Equityholder Rights Offering Shares, as applicable, that are not duly subscribed for pursuant to the HoldCo Noteholder Rights Offering or the HoldCo Equityholder Rights Offering, as applicable, by parties other than Commitment Parties (the "Backstop Commitment") at an implied 20% discount to the Plan Value, which is the price for the rights offering set forth in the PSA (the "Rights Offering Price").

The Company will pay the Commitment Parties upon the closing of the Rights Offering a Commitment Premium equal to 6.0% of the $580.0 million committed amount (the "Commitment Premium"). The Commitment Premium was fully earned as of January 19, 2017, the date the Backstop Approval Order was entered by the Bankruptcy Court. The Commitment Premium will be paid either in the form of new common stock at the Rights Offering Price, if the Plan is consummated as contemplated in the Plan Support Agreement, or in cash in the amount of 4.0% of the $580.0 million committed amount, if the Backstop Agreement is terminated other than as a result of a material breach by the Commitment Parties.

Exit Financing Commitment Letter: On February 8, 2017, the Debtors obtained a commitment letter (the "Commitment Letter") from Barclays Bank PLC (including any affiliates that may perform its responsibilities thereunder, "Barclays"), pursuant to which, in connection with the consummation of the Plan, Barclays has agreed to provide secured and unsecured financing in an aggregate amount of up to $2.4 billion, consisting of:

- A seven-year senior secured first lien term loan credit facility (the "Term Loan Facility") in an aggregate amount of $600.0 million;
- A five-year senior secured first lien revolving credit facility (the "Revolving Facility") in an aggregate amount of $400.0 million with an initial borrowing base (the "Borrowing Base") (which limits the aggregate amount of first lien debt under the Revolving Facility and the Term Loan Facility) of $1.0 billion with scheduled semi-annual redeterminations starting on October 1, 2017; and
- Senior unsecured bridge loans under senior unsecured bridge facilities (together with the Revolving Facility and the Term Loan Facility, the "Credit Facilities") in an aggregate amount of $1.4 billion, consisting of (i) a five-year bridge facility in an aggregate principal amount of $700.0 million, less the aggregate principal amount of privately placed five-year senior unsecured notes of the Company, if any, issued on or prior to the closing date of the Credit Facilities (the "Closing Date") and (ii) an eight-year bridge facility in an aggregate principal amount of $700.0 million, less the aggregate principal amount of privately placed eight-year senior unsecured notes of the Company, if any, issued on or prior to the Closing Date.

The Revolving Facility is anticipated to, among other things:

- have capacity for the Debtors to increase the commitments subject to certain conditions;
- have $100.0 million of the commitments available for the issuance of letters of credit; and
- require the Company to maintain (A) a maximum total net debt to EBITDAX ratio of (i) 4.25 to 1.0 as of the end of the first full fiscal quarter after the closing date and each subsequent fiscal quarter of 2017 and (ii) 4.0 to 1.0 as of the end of each fiscal quarter thereafter, (B) a minimum current ratio of 1.0 to 1.0 and (C) a minimum interest coverage ratio of 2.5 to 1.0.

The Term Loan Facility is anticipated to, among other things, have capacity for the Debtors to increase the commitments, with such increase in commitments subject to certain conditions.

The Revolving Facility and Term Loan Facility will include customary affirmative and negative covenants, including, among other things, as to compliance with laws, delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of properties (including oil and gas properties), maintenance of a lien on, and delivery of title information with respect to, 85% of the Debtors' proved oil and gas reserves, restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants.

The Revolving Facility and Term Loan Facility will include events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to material indebtedness; bankruptcy; material judgments; and certain ERISA events. Many events of default are subject to customary notice and cure periods.

The commitments of Barclays to provide the Credit Facilities are subject to certain conditions set forth in the Commitment Letter, including but not limited to the Plan Support Parties' reasonable satisfaction with the approval by the Bankruptcy Court of all actions to be taken, undertakings to be made and obligations to be incurred by the Debtors in connection with the Credit Facilities.

The Commitment Letter will terminate upon the occurrence of certain events described therein and the outside termination date for the Commitment Letter is May 9, 2017.

Based on the indicative pricing levels provided to the Company, the blended interest rate of the Credit Facilities on the effective date of the Plan (the "Blended Rate") is expected to be approximately 5.10% per annum. The actual Blended Rate on the effective date of the Plan will depend on factors including, without limitation, the size of each tranche of the Credit Facilities and the results of the syndication process of such Credit Facilities, and may therefore be higher or lower than 5.10% per annum.

As previously disclosed on a Current Report on Form 8-K filed with the SEC on February 9, 2017, on February 8, 2017, the Debtors filed a motion with the Bankruptcy Court seeking authorization to enter into and perform under the Commitment Letter and the other commitment papers. The motion was heard and approved during the Company's disclosure statement hearing on February 13, 2017.

Plan of Reorganization (Disclosure Statement)

We plan to emerge from our chapter 11 cases after we obtain approval from the Bankruptcy Court for a chapter 11 plan of reorganization. Among other things, a chapter 11 plan of reorganization will determine the rights and satisfy the claims of our prepetition creditors and security holders. The terms and conditions of a chapter 11 plan of reorganization will be determined through negotiations with our stakeholders and, possibly, decisions by the Bankruptcy Court.

On December 6, 2016, we filed an initial plan of reorganization and disclosure statement therefore. On January 17, 2017, we filed a revised plan of reorganization and disclosure statement therefore. On February 8, 2017, we filed a further revised plan of reorganization and disclosure statement therefore. On February 13, 2017, we filed amendments and further revisions to the plan of reorganization we filed on February 8, 2017 (the

"Plan") and to the disclosure statement therefore (the "Disclosure Statement"). The Court approved our Disclosure Statement on February 13, 2017 and scheduled a hearing to consider confirmation of the Plan for March 14, 2017.

Under the absolute priority scheme established by the Bankruptcy Code, unless our creditors agree otherwise, all of our prepetition liabilities and postpetition liabilities must be satisfied in full before the holders of our existing common stock can receive any distribution or retain any property under a chapter 11 plan of reorganization. The ultimate recovery to creditors and/or shareholders, if any, will not be determined until confirmation and implementation of a plan or plans of reorganization. We can give no assurance that any recovery or distribution of any amount will be made to any of our creditors or shareholders. Our plan of reorganization could result in any of the holders of our liabilities and/or securities, including our common stock, receiving no distribution on account of their interests and cancellation of their holdings. Moreover, a plan of reorganization can be confirmed, under the Bankruptcy Code, even if the holders of our common stock vote against the plan and even if the plan provides that the holders of our common stock receive no distribution on account of their equity interests.

Liabilities Subject to Compromise

We have applied Accounting Standards Codification ("ASC") 852, Reorganizations, in preparing the Consolidated Financial Statements included in this Annual Report on Form 10-K. In addition, the consolidated financial statements presented here include amounts classified as "liabilities subject to compromise." This amount represents estimates of known or potential prepetition claims expected to be resolved in connection with our chapter 11 proceedings. Additional amounts may be included in liabilities subject to compromise in future periods if we elect to reject executory contracts and unexpired leases as part of our chapter 11 cases. Due to the uncertain nature of many of the potential claims, the magnitude of potential claims is not reasonably estimable at this time. Potential claims not currently included with liabilities subject to compromise in our Consolidated Balance Sheets may be material. In addition, differences between amounts we are reporting as liabilities subject to compromise in this Annual Report on Form 10-K and the amounts attributable to such matters claimed by our creditors or approved by the Bankruptcy Court may be material. We will continue to evaluate our liabilities throughout the chapter 11 process, and we plan to make adjustments in future periods as necessary and appropriate. Such adjustments may be material.

Under the Bankruptcy Code, we may assume, assign, or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court and certain other conditions. If we reject a contract or lease, such rejection generally (1) is treated as a prepetition breach of the contract or lease, (2) subject to certain exceptions, relieves the Debtors of performing their future obligations under such contract or lease, and (3) entitles the counterparty thereto to a prepetition general unsecured claim for damages caused by such deemed breach. If we assume an executory contract or unexpired lease, we are generally required to cure any existing monetary defaults under such contract or lease and provide adequate assurance of future performance to the counterparty. Accordingly, any description of an executory contract or unexpired lease in this Annual Report on Form 10-K, including any quantification of our obligations under any such contract or lease, is wholly qualified by the rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and we expressly preserve all of our rights with respect thereto.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the components of liabilities subject to compromise included in our Consolidated Balance Sheets as of December 31, 2016:

	December 31, 2016
Accounts payable	$ 1,322
Accrued liabilities	6,303
Accrued interest payable	99,774
Debt	3,759,000
Accrued contract settlements	171,642
Liabilities subject to compromise	$ 4,038,041

Schedules and Statements – Magnitude of Potential Claims & Claims Resolution Process

On June 8, 2016, each of the Debtors filed a Schedule of Assets and Liabilities and Statement of Financial Affairs (collectively, the "Schedules and Statements") with the Bankruptcy Court setting forth, among other things, the assets and liabilities of the Debtors, subject to the assumptions filed in connection therewith. On October 14, 2016, Ultra Wyoming LGS, LLC ("UWLGS"), one of the Debtors and our indirect, wholly owned subsidiary, filed an amendment to its Schedules and Statements. The Schedules and Statements are subject to further amendment or modification. Certain holders of prepetition claims were required to file proofs of claim by the deadline for filing certain proofs of claims in the Debtors' chapter 11 cases, which deadline was September 1, 2016, for prepetition general unsecured claims and October 26, 2016, for governmental claims. Differences between amounts scheduled by the Debtors and claims by creditors will be investigated and resolved in connection with the claims resolution process. In light of the expected number of creditors, the claims resolution process may take considerable time to complete and will likely continue after our emergence from bankruptcy. Accordingly, the ultimate number and amount of allowed claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

To the best of our knowledge, we have notified all of our known current or potential creditors that the Debtors have filed chapter 11 cases. The Schedules and Statements set forth, among other things, the assets and liabilities of each of the Debtors, including executory contracts to which each of the Debtors is a party, and are subject to the qualifications and assumptions included therein and amendment or modification as our chapter 11 cases proceed.

Through the claims resolution process, differences in amounts scheduled by the Debtors and claims filed by creditors will be investigated and resolved, including through the filing of objections with the Bankruptcy Court where appropriate.

Many of the claims identified in the Schedules and Statements are listed as disputed, contingent or unliquidated. In addition, there are differences between the amounts for certain claims listed in the Schedules and Statements and the amounts claimed by our creditors. Such differences, as well as other disputes and contingencies will be investigated and resolved as part of our claims resolution process in our chapter 11 cases. Please refer to Note 11 for additional information about contingent matters and commitments related to certain claims filed in our chapter 11 cases.

Pursuant to the Federal Rules of Bankruptcy Procedure, some creditors who wished to assert prepetition claims against us and whose claims (i) were not listed in the Schedules and Statements or (ii) were listed in the

Schedules and Statements as disputed, contingent, or unliquidated, were required to file a proof of claim with the Bankruptcy Court prior to the bar date set by the court. The bar date for non-governmental creditors was September 1, 2016, and the bar date for governmental creditors was October 26, 2016.

The claims filed against the Debtors to date are voluminous. Further, it is possible that claimants will file amended or modified claims in the future, including modifications or amendments to assign values to claims originally filed with no designated value. The amended or modified claims may be material.

We plan to investigate and evaluate all filed claims in connection with our plan of reorganization. As a part of the claims resolution process, we anticipate working to resolve differences in amounts we listed in our Schedules and Statements and amounts of claims filed by our creditors. We have already identified, for example, claims that we believe should be disallowed by the Bankruptcy Court because they are duplicative, have been later amended or superseded, are without merit, are overstated or for other reasons. We have previously filed, and we will continue to file and prosecute objections with the Bankruptcy Court as necessary for claims we believe should be disallowed.

Tax Attributes; Net Operating Loss Carryforwards

We have substantial tax net operating loss carryforwards and other tax attributes. Under the U.S. Internal Revenue Code, our ability to use these net operating losses and other tax attributes may be limited if we experience a change of control, as determined under U.S. Internal Revenue Code. Accordingly, we obtained an order from the Bankruptcy Court that is intended to protect our ability to use our tax attributes by imposing certain notice procedures and transfer restrictions on the trading of the Company's common stock.

In general, the order applies to any person or entity that, directly or indirectly, beneficially owns (or would beneficially own as a result of a proposed transfer) at least 4.5% of the Company's common stock. Such persons are required to notify us and the Bankruptcy Court before effecting a transaction that might result in us losing the ability to use our tax attributes, and we have the right to seek an injunction to prevent the transaction if it might adversely affect our ability to use our tax attributes.

Any purchase, sale or other transfer of our equity securities in violation of the restrictions of the order is null and would be treated as invalid from the outset as an act in violation of a Bankruptcy Court order and would therefore confer no rights on a proposed transferee.

Costs of Reorganization

We have incurred and will continue to incur significant costs associated with our reorganization and the chapter 11 proceedings. We expect these costs, which are being expensed as incurred, will significantly affect our results of operations. In addition, a non-cash charge to write-off the unamortized debt issuance costs related to our funded indebtedness is included in "Reorganization items, net" as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases. For additional information about the costs of our reorganization and chapter 11 proceedings, see "Reorganization items, net" below.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the three and year months ended December 31, 2016:

	For the Twelve Months Ended December 31,		
	2016	2015	2014
Professional fees(1)	$ 11,781	$ —	$ —
Deferred financing costs(2)	18,742	—	—
Contract settlements(3)	17,350	—	—
Other(4)	(370)	—	—
Total Reorganization items, net	$ 47,503	$ —	$ —

(1) The year ended December 31, 2016 includes $6.4 million directly related to accrued, unpaid professional fees associated with the chapter 11 filings.

(2) A non-cash charge to write-off all of the unamortized debt issuance costs related to the unsecured Credit Agreement, unsecured Senior Notes issued by Ultra Resources, the unsecured 2018 Senior Notes issued by the Company and the unsecured 2024 Senior Notes issued by the Company is included in Reorganization items, net as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

(3) Includes accrued, unpaid amounts subject to Bankruptcy Court approval related to a settlement reached with Big West Oil, LLC in the amount of $17.35 million.

(4) Cash interest income earned for the period after the Petition Date on excess cash over normal invested capital.

Ability to Continue as a Going Concern

The Consolidated Financial Statements included in this Annual Report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The Consolidated Financial Statements do not reflect any adjustments that might result from the outcome of our chapter 11 proceedings. We have significant indebtedness, all of which we have reclassified to liabilities subject to compromise at December 31, 2016. Our level of indebtedness has adversely impacted and is continuing to adversely impact our financial condition. As a result of our financial condition, the defaults under our debt agreements, and the risks and uncertainties surrounding our chapter 11 proceedings, substantial doubt exists that we will be able to continue as a going concern.

1. SIGNIFICANT ACCOUNTING POLICIES:

Our accompanying consolidated financial statements have been prepared assuming that we will continue as a going concern, which contemplates realization of assets and the satisfaction of liabilities in the normal course of business for the twelve-month period following the date of these consolidated financial statements.

(a) Basis of presentation and principles of consolidation: The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All inter-company transactions and balances have been eliminated upon consolidation.

(b) *Cash and Cash Equivalents:* The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(c) *Restricted Cash:* Restricted cash primarily represents cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute.

(d) *Accounts Receivable:* Accounts receivable are stated at the historical carrying amount net of write-offs and an allowance for uncollectible accounts. The carrying amount of the Company's accounts receivable approximates fair value because of the short-term nature of the instruments. The Company routinely assesses the collectability of all material trade and other receivables.

(e) *Property, Plant and Equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on their respective useful life.

(f) *Oil and Natural Gas Properties:* The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932"). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company's proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2016 or 2014. During 2015, the Company recorded a $3.1 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected within ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials.

(g) *Inventories:* At December 31, 2016 and 2015, inventory of $4.9 million and $4.3 million, respectively, primarily includes the cost of pipe and production equipment that will be utilized during the 2017 drilling program and crude oil inventory. Materials and supplies inventories are carried at lower of cost or market and include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. The Company uses the weighted average method of recording its materials and supplies inventory. Crude oil inventory is valued at lower of cost or market.

(h) *Derivative Instruments and Hedging Activities:* The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability in the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations. The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 7).

(i) *Deferred Financing Costs:* During the year ended December 31, 2016, a non-cash charge to write-off all of the unamortized debt issuance costs related to the unsecured Credit Agreement, unsecured Senior Notes (as defined below) issued by Ultra Resources, Inc., the unsecured 2018 Senior Notes (as defined below) issued by the Company and the unsecured 2024 Senior Notes (as defined below) issued by the Company is included in Reorganization items, net in the accompanying Consolidated Statements of Operations as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases. At December 31, 2015, other current assets includes costs associated with the issuance of our revolving credit facility while costs associated with the issuance of our Senior Notes, 2018 Notes and 2024 Notes are presented as a direct deduction from the carrying amount of the related debt liability.

(j) *Income Taxes:* Income taxes are accounted for under 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 carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are recorded related to deferred tax assets based on the "more likely than not" criteria described in FASB ASC Topic 740, Income Taxes. In addition, the Company recognizes the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(k) *Earnings (loss) Per Share:* Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect. The weighted average shares in the table below do not consider any potential dilutive effects of the proposed plan of reorganization discussed in Note 1.

The following table provides a reconciliation of components of basic and diluted net income per common share:

	December 31, 2016	2015	2014
Net income	$ 56,151	$(3,207,220)	$542,851
Weighted average common shares outstanding during the period	153,378	153,192	153,136
Effect of dilutive instruments	703	—(1)	1,558
Weighted average common shares outstanding during the period including the effects of dilutive instruments	154,081	153,192	154,694
Net income per common share — basic	$ 0.37	$ (20.94)	$ 3.54
Net income per common share — fully diluted	$ 0.36	$ (20.94)	$ 3.51
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	1,437	—(1)	1,377

(1) Due to the net loss for the year ended December 31, 2015, 1.7 million shares for options and restricted stock units were anti-dilutive and excluded from the computation of net loss per share.

(l) *Use of Estimates:* Preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(m) *Accounting for Share-Based Compensation:* The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

(n) *Fair Value Accounting:* The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures (“FASB ASC 820”), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 8 for additional information.

(o) *Asset Retirement Obligation:* The initial estimated retirement obligation of properties is recognized as a liability with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations. As a full cost company, settlements for asset retirement obligations for abandonment are adjusted to the full cost pool. The asset retirement obligation is included within other long-term obligations in the accompanying Consolidated Balance Sheets.

(p) *Revenue Recognition:* The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances. The Company's imbalance obligations as of December 31, 2016 and December 31, 2015 were immaterial.

(q) *Capitalized Interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated, if any.

(r) *Capital Cost Accrual:* The Company accrues for exploration and development costs in the period incurred, while payment may occur in a subsequent period.

(s) *Reclassifications:* Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation.

(t) *Deposits and Retainers:* Deposits and retainers primarily consists of payments related to surety bonds.

(u) *Recent Accounting Pronouncements:* In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* ("ASU No. 2016-18"). The guidance requires that an explanation is included in the cash flow statement of the change in the total of (1) cash, (2) cash equivalents, and (3) restricted cash or restricted cash equivalents. The ASU also clarifies that transfers between cash, cash equivalents and restricted cash or restricted cash equivalents should not be reported as cash flow activities and requires the nature of the restrictions on cash, cash equivalents, and restricted cash or restricted cash equivalents to be disclosed. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)* ("ASU No. 2016-15"). The guidance requires that debt prepayment or debt extinguishment costs, including third-party costs, premiums paid, and other fees paid to lenders, be classified as cash outflows for financing activities. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

In March 2016, the FASB issued Accounting Standards Update ("ASU") 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* ("ASU No. 2016-09") to simplify some of the provisions in stock compensation accounting. The update simplifies the accounting for a stock payment's tax consequences and amends how excess tax benefits and a business's payments to cover the tax bills for the shares' recipients should be classified. The amendments allow companies to estimate the number of stock awards expected to vest and revises the withholding requirements for classifying stock awards as equity. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 with earlier application permitted. The Company is still evaluating the impact of ASU No. 2016-09 on its financial position and results of operations.

In February 2016, the FASB issued ASU 2016-02, *Leases* ("ASU No. 2016-02"). The guidance requires that lessees will be required to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months. The ASU will also require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative information. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 with earlier application permitted. The Company is still evaluating the impact of ASU No. 2016-02 on its financial position and results of operations.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory* ("ASU No. 2015-11"). Public companies will have to apply the amendments for reporting periods that start after December 15, 2016, including interim periods within those fiscal years. This ASU requires an entity to measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The company does not expect the adoption of ASU No. 2015-11 to have a material impact on its consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Interest — Imputation of Interest (Subtopic 835-30) —Simplifying the Presentation of Debt Issuance Costs.* In August 2015, the FASB issued ASU 2015-15, *Interest —Imputation of Interest (Subtopic 835-30) — Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. These ASUs require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Company adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption resulted in a reclassification that reduced current assets and current maturities of long-term debt by $19.4 million on the Company's Consolidated Balance Sheet at December 31, 2015. A non-cash charge to write-off all of the unamortized debt issuance costs is included in Reorganization items, net at December 31, 2016 as the related debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic

932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

We are 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, we have dedicated resources to the implementation, completed training of the new ASU's revenue recognition model, and begun contract review and documentation. The primary impacts to the Company of adopting ASU 2014-09 relate to principal versus agent considerations and the use of the entitlements method for oil and natural gas sales, both of which are continuing to be evaluated by the Company.

The Company is required to adopt the new standards in the first quarter of 2018 using one of two application methods: retrospectively to each prior reporting period presented (full retrospective method), or retrospectively with the cumulative effect of initially applying the guidance recognized at the date of initial application (the cumulative catch-up transition method). The Company is currently evaluating the available adoption methods.

In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU No. 2014-15") that requires management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when its plans alleviate substantial doubt about the Company's ability to continue as a going concern. ASU No. 2014-15 becomes effective for annual periods ending after December 15, 2016 and for interim reporting periods thereafter. The adoption of this ASU did not have a material impact on the Company's Consolidated Financial Statements.

2. ASSET RETIREMENT OBLIGATIONS:

The Company is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The following table summarizes the activities for the Company's asset retirement obligations for the years ended:

	December 31,	
	2016	2015
Asset retirement obligations at beginning of period	$146,210	$127,240
Accretion expense	10,252	9,122
Liabilities incurred	1,317	7,352
Liabilities settled	(170)	(1,861)
Revisions of estimated liabilities	(436)	4,357
Asset retirement obligations at end of period	157,173	146,210
Less: current asset retirement obligations	(239)	(305)
Long-term asset retirement obligations	$156,934	$145,905

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

3. OIL AND GAS PROPERTIES:

	December 31, 2016	December 31, 2015
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 10,752,642	$ 10,480,165
Less: Accumulated depletion, depreciation and amortization(1)	(9,742,176)	(9,629,020)
	1,010,466	851,145

On a unit basis, DD&A was $0.44, $1.38 and $1.18 per Mcfe for the years ended December 31, 2016, 2015 and 2014, respectively.

(1) During 2015, the Company recorded a $3.1 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected within ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials.

4. PROPERTY, PLANT AND EQUIPMENT:

	December 31,			
	2016			2015
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Computer equipment	2,840	(2,237)	603	794
Office equipment	309	(171)	138	196
Leasehold improvements	486	(301)	185	267
Land	4,637	—	4,637	4,637
Other	12,460	(10,328)	2,132	2,950
Property, plant and equipment, net	$20,732	$ (13,037)	$ 7,695	$ 8,844

5. DEBT AND OTHER LONG-TERM LIABILITIES:

	December 31, 2016	December 31, 2015
Total Debt:		
6.125% Senior Notes due 2024	$ 850,000	$ 850,000
5.75% Senior Notes due 2018	450,000	450,000
Senior Notes issued by Ultra Resources, Inc.	1,460,000	1,460,000
Credit Agreement	999,000	630,000
Total current portion of long-term debt	3,759,000	3,390,000
Less: Deferred financing costs(1)	—	(19,447)
Less: Liabilities subject to compromise(2) (See Note 1)	(3,759,000)	—
Total current portion of long-term debt not subject to compromise	—	$3,370,553

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	December 31, 2016	December 31, 2015
	$	
Other long-term obligations:		
Other long-term obligations	177,088	$ 165,784

Aggregate maturities of debt at December 31, 2016:(2)

2017	2018	2019	2020	2021	Beyond 5 years	Total
$3,759,000	$ —	$ —	$ —	$ —	$ —	$ 3,759,000

(1) A non-cash charge to write-off all of the unamortized debt issuance costs related to the unsecured Credit Agreement, the unsecured Senior Notes issued by Ultra Resources, the unsecured 2018 Senior Notes issued by the Company and the unsecured 2024 Senior Notes issued by the Company is included in Reorganization items, net in the Consolidated Statements of Operations as these debt instruments are expected to be impacted by the pendency of the Company's chapter 11 cases.

(2) We have significant indebtedness, all of which is included with liabilities subject to compromise at December 31, 2016 in the Consolidated Balance Sheets. Our level of indebtedness has adversely impacted and is continuing to adversely impact our financial condition. As a result of our financial condition, the defaults under our debt agreements and the risks and uncertainties surrounding our chapter 11 proceedings, substantial doubt exists that we will be able to continue as a going concern. As a result, we have classified all of our total outstanding debt as short-term.

Ultra Resources, Inc.

Bank indebtedness. Ultra Resources, Inc. ("Ultra Resources"), a wholly owned subsidiary of the Company, is a party to the Credit Agreement. Ultra Resources' obligations under the Credit Agreement are guaranteed by the Company and UP Energy Corporation, a wholly owned subsidiary of the Company.

Ultra Resources' filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated its obligations under the Credit Agreement. Other events of default are also present with respect to the Credit Agreement, including a failure to make interest payments and, as described below, a failure to deliver annual audited consolidated financial statements without a going concern qualification, a failure to meet the minimum PV-9 ratio covenant and a failure to comply with the consolidated leverage covenant in the Credit Agreement at the end of the first quarter of 2016. The Credit Agreement provides that upon the acceleration of Ultra Resources' obligations under the Credit Agreement, the outstanding balance of loans extended under the Credit Agreement comes due, unpaid interest accrued as of the time of the acceleration comes due, and any fees or other obligations of the borrower come due. Under the Bankruptcy Code, the creditors under the Credit Agreement are stayed from taking any action against Ultra Resources or any of the other Debtors as a result of the default.

Prior to April 29, 2016, loans under the Credit Agreement bore interest, at the borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus a margin based on a grid of the borrower's consolidated leverage ratio, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the borrower's consolidated leverage ratio.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Credit Agreement requires us to deliver annual audited, consolidated financial statements for the Company without a "going concern" or like qualification or explanation. On March 15, 2016, we delivered an audit report with respect to the financial statements in our 2015 Annual Report on Form 10-K that included an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern."

The Credit Agreement contains a consolidated leverage covenant, pursuant to which Ultra Resources is required to maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0. Based on Ultra Resources' EBITDAX for the trailing four fiscal quarters ended March 31, 2016, we were not in compliance with this consolidated leverage covenant at March 31, 2016 (the ratio was 4.6 times at March 31, 2016).

The Credit Agreement contains a PV-9 covenant, pursuant to which Ultra Resources is required to maintain a minimum ratio of the discounted net present value of its oil and gas properties to its total funded consolidated debt of 1.5 times. We were required to report whether we were in compliance with this covenant on April 1, 2016. Based on the PV-9 of its oil and gas properties at December 31, 2015, Ultra Resources failed to comply with the PV-9 ratio covenant under the Credit Agreement (the ratio was 0.9 times at December 31, 2015).

Senior Notes. Ultra Resources has outstanding $1.46 billion of senior notes ("Senior Notes") which were issued pursuant to a certain Master Note Purchase Agreement dated as of March 6, 2008 (as amended, supplemented or otherwise modified, the "MNPA"). The Senior Notes rank pari passu with the Credit Agreement. Payment of the Senior Notes is guaranteed by the Company and by UP Energy Corporation. The Senior Notes are subject to representations, warranties, covenants and events of default similar to those in the Credit Agreement.

Ultra Resources' filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated its obligations under the MNPA and the Senior Notes. Other events of default are also present with respect to the MNPA, including a failure to comply with the consolidated leverage covenant at the end of the first quarter of 2016 and a failure to make principal and interest payments due under the Ultra Resources' Senior Notes. The MNPA provides that upon the acceleration of Ultra Resources' obligations under the MNPA and the Senior Notes, among other matters, the Senior Notes are deemed to have matured, the unpaid principal balance of the Senior Notes comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable make-whole amount (as determined pursuant to the MNPA) comes due. Under the Bankruptcy Code, the creditors under the Senior Notes are stayed from taking any action against Ultra Resources or any of the other the Debtors as a result of the default.

The MNPA contains a consolidated leverage covenant, pursuant to which Ultra Resources is required to maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0. Based on Ultra Resources' EBITDAX for the trailing four fiscal quarters ended March 31, 2016, we were not in compliance with this consolidated leverage covenant at March 31, 2016 (the ratio was 4.6 times at March 31, 2016).

On March 1, 2016, we failed to make an interest payment of approximately $40.0 million and a principal payment of $62.0 million, each of which was due March 1, 2016 under the terms of the Senior Notes. We entered into a forbearance agreement related to the failure to make these payments with the holders of the Senior Notes, and we filed the chapter 11 petitions without making the payments before the forbearance period expired.

Interest Expense. No interest expense has been recognized with respect to the Credit Agreement or the Senior Notes subsequent to the Petition Date.

Ultra Petroleum Corp. Senior Notes

The Company's filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated the Company's obligations under the 2024 Notes and the 2018 Notes. Additionally, other events of default, including cross-defaults, are present due to the failure to make interest payments and other matters. Under the indentures pursuant to which the 2024 Notes and the 2018 Notes, respectively, were issued, upon the acceleration of the Company's obligations under the 2024 Notes and the 2018 Notes, among other matters, the 2024 Notes and the 2018 Notes, respectively, are deemed to have matured, the unpaid principal balance of the 2024 Notes and the 2018 Notes, respectively, comes due, unpaid interest accrued as of the time of the acceleration comes due, and any applicable premiums (as determined pursuant to the indentures) comes due. Under the Bankruptcy Code, the creditors under the 2024 Notes and the 2018 Notes are stayed from taking any action against the Debtors as a result of the default.

Senior Notes due 2024: On September 18, 2014, the Company issued $850.0 million of 6.125% Senior Notes due 2024 ("2024 Notes"). The 2024 Notes are general, unsecured senior obligations of the Company and mature on October 1, 2024. The 2024 Notes rank equally in right of payment to all existing and future senior indebtedness of the Company and effectively rank junior to all future secured indebtedness of the Company (to the extent of the value of the collateral securing such indebtedness). The 2024 Notes are not guaranteed by the Company's subsidiaries and, as a result, are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. The 2024 Notes are subject to covenants that restrict the Company's ability to incur indebtedness, make distributions and other restricted payments, grant liens, use the proceeds of asset sales, make investments and engage in affiliate transactions.

Interest due under the 2024 Notes is payable each April 1 and October 1. On April 1, 2016, we elected to defer making an interest payment on the 2024 Notes of approximately $26.0 million due April 1, 2016. The indenture governing the 2024 Notes provides a 30-day grace period for us to make this interest payment. We did not make this interest payment before the end of the grace period, which resulted in an event of default under the indenture governing the 2024 Notes.

Senior Notes due 2018: On December 12, 2013, the Company issued $450.0 million of 5.75% Senior Notes due 2018 ("2018 Notes"). The 2018 Notes are general, unsecured senior obligations of the Company and mature on December 15, 2018. The 2018 Notes rank equally in right of payment to all existing and future senior indebtedness of the Company and effectively rank junior to all future secured indebtedness of the Company (to the extent of the value of the collateral securing such indebtedness). The 2018 Notes are not guaranteed by the Company's subsidiaries and, as a result, are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. The 2018 Notes are subject to covenants that restrict the Company's ability to incur indebtedness, make distributions and other restricted payments, grant liens, use the proceeds of asset sales, make investments and engage in affiliate transactions. Interest due under the 2018 Notes is payable each June 15 and December 15.

The Company's filing of the chapter 11 petitions described in Note 1 constituted an event of default that accelerated the Company's obligations under the 2024 Notes and the 2018 Notes. Additionally, other events of default, including cross-defaults resulting from the acceleration of indebtedness outstanding under the Credit Agreement and the Ultra Resources' Senior Notes, are present due to the failure to make interest payments and other matters. Under the Bankruptcy Code, the creditors under the 2024 Notes and the 2018 Notes are stayed from taking any action against the Debtors as a result of the Company's bankruptcy filings.

Interest Expense. No interest expense has been recognized with respect to the 2024 Notes or the 2018 Notes subsequent to the Petition Date.

Other long-term obligations: These costs primarily relate to the long-term portion of production taxes payable and asset retirement obligations.

6. SHARE BASED COMPENSATION:

The Company sponsors a share based compensation plan: the 2015 Stock Incentive Plan ("2015 Plan"). The Plan is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plan is an important component of the total compensation package offered to the Company's key service providers, and reflects the importance that the Company places on motivating and rewarding superior results.

The purpose of the 2015 Plan is to foster and promote the long-term financial success of the Company and to increase shareholder value by attracting, motivating and retaining key employees, consultants, and outside directors, and providing such participants with a program for obtaining an ownership interest in the Company that links and aligns their personal interests with those of the Company's shareholders, and thus, enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the Plan permits the granting of incentive stock options, non-statutory stock options, stock appreciation rights, restricted stock, and other stock-based awards, some of which may require the satisfaction of performance-based criteria in order to be payable to participants. The Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions and estimates forfeitures that may occur. The Committee may grant awards under the 2015 Plan until December 31, 2024.

Valuation and Expense Information

	Year Ended December 31,		
	2016	2015	2014
Total cost of share-based payment plans	$8,013	$6,137	$8,640
Amounts capitalized in oil and gas properties and equipment	$2,451	$2,009	$3,173
Amounts charged against income, before income tax benefit	$5,562	$4,128	$5,467
Amount of related income tax benefit recognized in income before valuation allowances	$2,216	$1,645	$2,285

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2016, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in the First Column)
	(000's)		(000's)
Equity compensation plans approved by security holders	346	$ 60.64	4,339
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	346	$ 60.64	4,339

Changes in Stock Options and Stock Options Outstanding

The following table summarizes the changes in stock options for the three year period ended December 31, 2016:

	Number of Options (000's)	Weighted Average Exercise Price (US$)		
Balance, December 31, 2013	1,246	$16.97	to	$98.87
Forfeited	(513)	$33.57	to	$75.18
Exercised	(43)	$16.97	to	$25.68
Balance, December 31, 2014	690	$25.68	to	$98.87
Forfeited	(171)	$25.68	to	$75.18
Balance, December 31, 2015	519	$49.05	to	$98.87
Forfeited	(173)	$50.15	to	$75.18
Balance, December 31, 2016	346	$49.05	to	$98.87

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2016:

	Options Outstanding and Exercisable			
Range of Exercise Price	Number Outstanding (000's)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value
$49.05 — $62.23	210	0.31	$ 54.12	$ —
$51.60 — $98.87	136	1.45	$ 70.64	$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $7.23 per share on December 31, 2016, which would have been received by the option holders had all option holders exercised their options as of that date. There were no in-the-money options exercisable as of December 31, 2016.

The following table summarizes information about the weighted-average grant-date fair value of share options:

	2016	2015	2014
Options forfeited during the year	$25.17	$28.00	$24.40

As of December 31, 2011, all options were fully vested; therefore, no options vested during the years ended December 31, 2016, 2015 or 2014. There were no stock options exercised during the years ended December 31, 2016, 2015 and 2014.

At December 31, 2016, there was no unrecognized compensation cost related to non-vested, employee stock options as all options fully vested as of December 31, 2011.

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. During 2015 and 2014, the Company offered a Long Term Incentive Plan ("LTIP") in order to further align the interests of key employees with shareholders and to give key employees the opportunity to share in the long-term performance of the Company when specific corporate financial and operational goals are achieved. Each LTIP covers a performance period of three years.

Under each LTIP, the Committee establishes a percentage of base salary for each participant that is multiplied by the participant's base salary at the beginning of the performance period and individual performance level to derive a Long Term Incentive Value as a "target" value. This "target" value corresponds to the number of shares of the Company's common stock the participant is eligible to receive if the participant is employed by the Company through the date the award vests and if the target level for all performance measures is met. In addition, each participant is assigned threshold and maximum award levels in the event the Company's actual performance is below or above target levels.

Time-Based Measure and Performance-Based Measures:

For each LTIP, the Compensation Committee established time-based and performance-based measures at the beginning of each three-year performance period. For the LTIP awards in 2015 and 2014, the Compensation Committee established the following performance-based measures: return on capital employed, debt level, and reserve replacement ratio. At the time the LTIP awards are awarded, the fair value of the time-based and performance-based component of the LTIP award is based on the average high and low market price of the Company's common stock on the date of the award.

Market-Based Measure (Total Shareholder Return):

LTIP awards granted to officers during 2016 and 2015, included an additional performance metric, Total Shareholder Return. The grant-date fair value related to the market-based condition was calculated using a Monte Carlo simulation.

Valuation Assumptions

The Company estimates the fair value of the market condition related to the LTIP awards on the date of grant using a Monte Carlo simulation with the following assumptions:

	2015 LTIP	2014 LTIP
Volatility of common stock	40.1%	39.0%
Average volatility of peer companies	46.5%	n/a
Average correlation coefficient of peer companies	0.454	n/a
Risk-free interest rate	1.02%	0.66%

Stock-Based Compensation Cost:

For the year ended December 31, 2016, the Company recognized $4.7 million in pre-tax compensation expense related to the 2015 and 2014 LTIP awards. For the year ended December 31, 2015, the Company recognized $2.9 million in pre-tax compensation expense related to the 2015, 2014 and 2013 LTIP awards. For the year ended December 31, 2014, the Company recognized $6.3 million in pre-tax compensation expense related to the 2014, 2013 and 2012 LTIP awards. The amounts recognized during the year ended December 31, 2016 assumes that performance objectives between less than threshold and up to maximum are attained for the 2015 LTIP and 2014 LTIP plans. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2016, for each of the three-year performance periods is expected to be approximately $10.3 million and $9.5 million related to the 2015 and 2014 LTIP awards of restricted stock units, respectively.

Based on the Company's achievement relative to the 2013 LTIP's performance-based measures, and based on the continued employment with the Company by those participants who received a payment in connection with the 2013 LTIP relative to the 2013 LTIP's time-based measures, during the first quarter of 2016, the Compensation Committee approved payment of the 2013 LTIP. This was the first payment of an LTIP since our LTIPs were modified in 2013 to include time-based and performance-based measures. As such, the Compensation Committee elected to pay the time-based portion of the LTIP awards in cash at the award value and the performance-based portion of the LTIP awards in shares of our common stock. The payout of the 2013 LTIP was during the first quarter of 2016 and totaled $3.8 million (resulting in delivery of 132,843 net shares of our common stock to eligible participants in the 2013 LTIP).

7. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. As a result of its hedging activities, the Company may realize prices that are less than or greater than the spot prices that it would have received otherwise.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the Consolidated Balance Sheets and the associated unrealized gains and losses are recorded as current expense or income in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the Consolidated Statements of Cash Flows.

Commodity Derivative Contracts: At December 31, 2016, the Company had no open commodity derivative contracts to manage price risk on a portion of its production.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2016, 2015 and 2014:

	For the Year Ended December 31,		
Commodity Derivatives:	**2016**	**2015**	**2014**
Realized gain (loss) on commodity derivatives-natural gas(1)	$—	$ 146,801	$ (48,170)
Realized gain on commodity derivatives-crude oil(1)	—	—	506
Unrealized (loss) gain on commodity derivatives(1)	—	(104,190)	130,066
Total gain on commodity derivatives	$—	$ 42,611	$ 82,402

(1) Included in gain on commodity derivatives in the Consolidated Statements of Operations.

8. FAIR VALUE MEASUREMENTS:

As required by FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a three level hierarchy for measuring fair value. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

Assets and Liabilities Measured on a Non-recurring Basis

The Company uses fair value to determine the value of its asset retirement obligations. The inputs used to determine such fair value under the expected present value technique are primarily based upon internal estimates prepared by reservoir engineers for costs of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties and would be classified Level 3 inputs.

Fair Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the immediate or short-term maturity of these financial instruments. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. We use available market data and valuation methodologies to estimate the fair value of our fixed rate debt and the fair values presented in the tables below reflect original maturity dates for each of the debt instruments. The inputs utilized to estimate the fair value of the Company's fixed rate debt are considered Level 2 fair value inputs. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact our financial position, results of operations or cash flows.

	December 31, 2016(1)		December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7.31% Notes due March 2016, issued 2009	62,000	64,266	62,000	63,604
4.98% Notes due January 2017, issued 2010	116,000	123,967	116,000	113,420
5.92% Notes due March 2018, issued 2008	200,000	224,025	200,000	191,985
5.75% Notes due December 2018, issued 2013	450,000	465,630	450,000	111,451
7.77% Notes due March 2019, issued 2009	173,000	204,854	173,000	174,488
5.50% Notes due January 2020, issued 2010	207,000	233,932	207,000	185,052
4.51% Notes due October 2020, issued 2010	315,000	337,528	315,000	258,520
5.60% Notes due January 2022, issued 2010	87,000	99,983	87,000	73,034
4.66% Notes due October 2022, issued 2010	35,000	38,225	35,000	25,558
6.125% Notes due October 2024, issued 2014	850,000	893,325	850,000	206,321
5.85% Notes due January 2025, issued 2010	90,000	106,299	90,000	70,756
4.91% Notes due October 2025, issued 2010	175,000	193,665	175,000	115,911
Credit Facility due October 2016	999,000	999,000	630,000	630,000
	$ 3,759,000	$ 3,984,699	$ 3,390,000	$ 2,220,100

(1) At December 31, 2016, the debt included in the table above is a component of liabilities subject to compromise in our Consolidated Balance Sheets. See Note 1.

9. INCOME TAXES:

Income (loss) before income tax benefit is as follows:

	Year Ended December 31,		
	2016	2015	2014
United States	$134,959	$(3,249,590)	$505,689
Foreign	(79,462)	37,966	31,338
Total	$ 55,497	$(3,211,624)	$537,027

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The consolidated income tax (benefit) provision is comprised of the following:

	Year Ended December 31,		
	2016	2015	2014
Current tax:			
U.S. federal, state and local	$ (72)	$ —	$ (110)
Foreign	(583)	(3,414)	(6,709)
Total current tax (benefit)	(655)	(3,414)	(6,819)
Deferred tax:			
Foreign	1	(990)	995
Total deferred tax (benefit) expense	1	(990)	995
Total income tax (benefit)	$(654)	$(4,404)	$(5,824)

The income tax provision (benefit) from continuing operations differs from the amount that would be computed by applying the U.S. federal income tax rate of 35% to pretax income as a result of the following:

	Year Ended December 31,		
	2016	2015	2014
Income tax provision (benefit) computed at the U.S. statutory rate	$ 19,424	$(1,124,069)	$ 187,959
State income tax (benefit) provision net of federal effect	(2,335)	(12,998)	8,023
Valuation allowance	(31,083)	1,147,619	(199,038)
Tax effect of rate change	—	12,898	15,457
Foreign rate differential	17,388	(26,740)	(16,314)
Other, net	(4,048)	(1,114)	(1,911)
Total income tax (benefit)	$ (654)	$ (4,404)	$ (5,824)

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
(Debtor-in-Possession)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The tax effects of temporary differences that give rise to significant components of the Company's deferred tax assets and liabilities are as follows:

	December 31,	
	2016	2015
Deferred tax assets:		
Property and equipment	603,045	776,504
Deferred gain	40,867	44,593
U.S. federal tax credit carryforwards	15,967	16,144
U.S. net operating loss carryforwards	428,212	319,673
U.S. state net operating loss carryforwards	71,323	61,919
Non-U.S. net operating loss carryforwards	30,211	9,142
Asset retirement obligations	55,700	51,815
Liabilities subject to compromise-contract settlement	59,166	—
Incentive compensation/other, net	16,088	28,711
	1,320,579	1,308,501
Valuation allowance	(1,270,935)	(1,307,076)
Net deferred tax assets	$ 49,644	$ 1,425
Deferred tax liabilities:		
Liabilities subject to compromise-interest	35,498	—
Liabilities subject to compromise-interest (non-U.S.)	14,146	—
Other — non-US	—	1,424
Net tax liabilities	$ 49,644	$ 1,424
Net tax asset	$ —	$ 1

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible or before the attributes expire unused. Among other items, management considers the scheduled reversal of deferred tax liabilities, historical taxable income, projected future taxable income, and available tax planning strategies.

At December 31, 2016 and 2015, the Company recorded a valuation allowance against certain deferred tax assets of $1.3 billion and $1.3 billion, respectively. Some or all of this valuation allowance may be reversed in future periods if future taxable income of the appropriate character is available to recognize certain deferred tax assets. The Company's valuation allowance decreased by $36.1 million from December 31, 2015 to December 31, 2016. Of this amount, $31.1 million reduced the Company's current year deferred tax benefit, and $5.1 million was reflected through shareholders' equity.

As of December 31, 2016, the Company had approximately $13.7 million of U.S. federal alternative minimum tax (AMT) credits available to offset regular U.S. Federal income taxes. These AMT credits do not expire and can be carried forward indefinitely. The Company has $0.5 million of general business credits available to offset U.S. federal income taxes. These general business credits expire in 2032. In addition, the Company has $1.6 million of foreign tax credit carryforwards, which will expire in 2017.

The Company has a U.S. federal tax net operating loss carryforward of $1.2 billion which will be carried forward to offset taxable income generated in future years, and if unutilized, will expire between 2033 and 2036. The Company has Pennsylvania state tax net operating loss carry forwards of $1.1 billion which will expire between 2031 and 2036. The Company has Utah state tax net operating loss carry forwards of $80.8 million which will expire between 2033 and 2036. The Company has immaterial state tax net operating loss carry forwards in other jurisdictions, none of which expire prior to 2020. Without regard to the recorded valuation allowance, if the Company experiences an ownership change as determined under Section 382 of the Internal Revenue Code, our ability to utilize our substantial net operating loss carryforwards and other tax attributes may be limited, if we can use them at all.

The Company has a Canada Federal and Provincial tax loss carryforward remaining after carryback of $111.9 million that will be carried forward to offset taxable income generated in future years and will expire in 2036.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2016.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statements of Operations. The Company has not incurred any interest or penalties associated with unrecognized tax benefits.

The Company files a consolidated federal income tax return in the United States federal jurisdiction and various combined, consolidated, unitary, and separate filings in several states, and international jurisdictions. With certain exceptions, the income tax years 2013 through 2016 remain open to examination by the major taxing jurisdictions in which the Company has business activity.

The undistributed earnings of the Company's U.S. subsidiaries are considered to be indefinitely invested outside of Canada. Accordingly, no provision for Canadian income taxes and/or withholding taxes has been provided thereon.

10. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer 100% of their compensation, subject to limitations. The Company matches all of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $2.3 million, $2.3 million and $2.0 million for the years ended December 31, 2016, 2015 and 2014, respectively.

11. COMMITMENTS AND CONTINGENCIES:

The commencement of the chapter 11 proceedings automatically stayed certain actions against the Company, including actions to collect prepetition liabilities or to exercise control over the property of the Company's bankruptcy estates, and the Company has obtained from the Bankruptcy Court authority to pay certain prepetition claims in the ordinary course of business notwithstanding the commencement of the chapter 11 proceedings. A future plan of reorganization in the chapter 11 proceedings, when confirmed, will provide for the treatment of claims against the Company's bankruptcy estates, including prepetition liabilities that have not otherwise been satisfied or addressed during the chapter 11 proceedings.

Indebtedness Claims

The chapter 11 filings by the Company and its various subsidiaries, including Ultra Resources, constituted events of default under the Company's debt agreements. See Note 5 of this Annual Report on Form 10-K for more information about the debt agreements. On or around September 1, 2016, many of the holders of this indebtedness filed proofs of claim with the Bankruptcy Court, asserting claims for the outstanding balance of the indebtedness, unpaid interest that had accrued by the petition dates, interest that has accrued since the petition dates (including interest at the default rates under the debt agreements), make-whole amounts, and other fees and obligations under the debt agreements. On December 29, 2016, holders of certain Senior Notes (as defined below) filed a complaint initiating an adversary proceeding against us in our chapter 11 cases. In the complaint, among other matters, the noteholders allege that there is a make-whole amount due under the Senior Notes as a result of our filing the chapter 11 cases, which they assert is "no less than $200,725,869, exclusive of any interest thereon." On January 13, 2017, holders of certain other Senior Notes intervened to join the adversary proceeding as plaintiffs. On January 30, 2017, we filed a motion to dismiss the complaint. On February 10, 2017, both noteholder groups objected to our motion to dismiss. On February 13, 2017, the Court set a briefing schedule and a hearing date for April 20, 2017 for resolution of the make-whole and interest claims. At this time, we are not able to determine the likelihood or range of amounts attributable to claims for postpetition interest, make-whole amounts, or other fees and obligations under the debt agreements. We anticipate these claims will be resolved during our chapter 11 proceedings, although it is possible resolution of some of these matters could occur after we emerge from chapter 11.

Rockies Express Pipeline

On February 26, 2016, we received a letter from Sempra Rockies Marketing, LLC ("Sempra") alleging that we were in breach of our Capacity Release Agreement, dated March 5, 2009 (the "Capacity Agreement"), resulting from nonpayment of fees for transportation service and notifying us that Sempra was authorized to recall the capacity released to us under the Capacity Agreement and to pursue any claims for damages or other remedies to which Sempra was entitled. On March 8, 2016, we received a letter from Sempra notifying us that Sempra was exercising its alleged right to permanently recall the 50,000 MMBtu/day of capacity on the Rockies Express Pipeline pursuant to the Capacity Agreement and that the recall would be effective as of March 9, 2016. On August 25, 2016, Sempra filed a proof of claim with the Bankruptcy Court for approximately $63.8 million. On October 28, 2016, we filed an objection to Sempra's proof of claim. On December 20, 2016, Sempra filed a response to the Company's objection. On November 28, 2016, the Bankruptcy Court entered a scheduling order establishing March 2, 2017 as the trial date for the claim objection. On January 23, 2017, the Bankruptcy Court entered an updated scheduling order establishing April 18, 2017 as the trial date for the claim objection. Our estimate of the potential exposure in connection with the Capacity Agreement and Sempra's claim filed in our chapter 11 proceedings ranges from $4.2 million, which represents amounts Sempra paid to Rockies Express attributable to the capacity released to us under the Capacity Agreement prior to Sempra's recalling such capacity, to $63.8 million. We anticipate Sempra's claims will be resolved through our chapter 11 proceedings.

On April 4, 2016, we received a demand for payment and notice of enforcement from Rockies Express Pipeline LLC ("REX") in connection with the transportation agreement related to the Rockies Express Pipeline, pursuant to which Rockies Express demanded payment from us of $303.2 million by April 20, 2016. On April 14, 2016, REX filed a lawsuit against us in Harris County, Texas alleging breach of contract and seeking damages related to the alleged breach. On August 26, 2016, REX filed a proof of claim with the Bankruptcy Court for $303.3 million. The Company objected to REX's proof of claim. On January 12, 2017, REX and the Company entered into a settlement agreement resolving REX's proof of claim. Pursuant to the settlement, we agreed to make a cash payment to REX of $150.0 million six months after the Company emerges from chapter 11, but no later than October 30, 2017, and to provide REX an allowed general unsecured claim under our Plan in that amount. Additionally, in connection with the settlement, we agreed to enter into, with REX, a new seven-year agreement, commencing December 1, 2019, for firm transportation service on the Rockies Express Pipeline, west-to-east, of 200,000 dekatherms per day at a rate of approximately $0.37 per dekatherm, or approximately $26.8 million annually. The settlement with REX has been submitted to the Bankruptcy Court for approval and will be implemented in connection with the plan of reorganization.

Royalties

On April 19, 2016, the Company received a preliminary determination notice from the Office of Natural Resources Revenue ("ONRR") asserting that the Company's allocation of certain processing costs and plant fuel use at certain processing plants were impermissibly charged as deductions in the determination of royalties owed under Federal oil and gas leases. During the second quarter of 2016, the Company responded to the preliminary determination asserting the reasonableness of its allocation methodology of such costs, noting several matters we believed should have been considered in the preliminary determination notice. The ONRR unbundling review could ultimately result in an order for payment of additional royalties under the Company's Federal oil and gas leases for current and prior periods. On October 27, 2016, ONRR filed a proof of claim with the Bankruptcy Court asserting approximately $35.1 million in claims attributable to the Company's royalty calculations. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

Oil Sales Contract

On April 29, 2016, the Company received a letter from counsel to Sunoco Partners Marketing & Terminals L.P. ("SPMT") asserting that (1) the Company had breached, by anticipatory repudiation, a contract for the purchase and sale of crude oil between Ultra Resources and SPMT and (2) the contract was terminated. In the letter, SPMT demanded payment for damages resulting from the breach in the amount of $38.6 million. On August 31, 2016, SPMT filed a proof of claim with the Bankruptcy Court for $16.9 million. We dispute SPMT's positions in the letter and its proof of claim. On December 13, 2016, we filed an objection to SPMT's proof of claim, and on December 14, 2016, we filed an adversary proceeding against SPMT related to its breach of the contract during the prepetition period. On January 18, 2017, SPMT filed a reply to our objection SPMT's proof of claim and an answer to our complaint in the adversary proceeding. At this time, we are not able to determine the likelihood or range of damages owed to SPMT, if any, related to this matter, or, if and when such amounts are assessed, whether such amounts would be material. SPMT is a member of our official committee of unsecured creditors. We anticipate SPMT's claims will be resolved through our chapter 11 proceedings.

The Company is a party, with Big West Oil, LLC ("Big West"), to several prepetition contracts (the "Crude Contracts") for the purchase and sale of crude oil. On April 26, 2016, Big West Oil LLC ("Big West") and the Company entered into a Temporary Suspension of Contracts and Interim Crude Oil Purchase and Sale Agreement ("Suspension Agreement"), pursuant to which the parties suspended performance under the prepetition contracts. On August 30, 2016, Big West filed a proof of claim with the Bankruptcy Court for $32.6 million. The Company objected to Big West's proof of claim. On January 20, 2017, Big West and the Company reached an agreement settling and resolving Big West's proof of claim. Pursuant to the settlement, we agreed to make a cash payment to Big West, within six months of our emergence from chapter 11, of $17.35 million to provide Big West with an allowed general unsecured claim against all of the Ultra Entities in that amount and that all of our prepetition contracts with Big West, including the Suspension Agreement, would be rejected (with no additional damages other than the $17.35 million payment) in connection with our plan of reorganization. Additionally, in connection with the settlement, we and Big West agreed to enter into two new, two-year, contracts for the purchase and sale of crude oil we produce in Wyoming and Utah. The settlement with Big West has been submitted to the Bankruptcy Court for approval and will be implemented in connection with the plan of reorganization.

Operating Lease

During December 2012, the Company sold its system of pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming and entered into a long-term, triple net lease agreement (the "Pinedale Lease Agreement") relating to the use of the Pinedale LGS. The Pinedale Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. The Company currently projects that lease payments related to the Pinedale Lease Agreement will total approximately $229.9 million.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease

The Company maintains office space in Colorado, Texas, Wyoming and Utah with total remaining commitments for office leases of $6.6 million at December 31, 2016; ($1.3 million in 2017; $1.2 million in 2018; $1.2 million in 2019; $1.2 million in 2020; and $1.1 million in 2021 with the remainder due beyond five years).

During the years ended December 31, 2016, 2015 and 2014, the Company recognized expense associated with its office leases in the amount of $1.5 million, $1.3 million, and $1.0 million, respectively.

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 9, 2017, the Company has long-term natural gas delivery commitments of 2.8 MMMBtu in 2018 under existing agreements. As of February 9, 2017, the Company has long-term crude oil delivery commitments of 1.6 MMBbls in 2017, 1.7 MMBbls in 2018 and 0.3 MMBbls in 2019 under existing agreements. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Other Claims

The Company is party to a lawsuit related to disputes with respect to overriding royalty interests in certain of our operated leases in Pinedale, Wyoming. At this time, no determination of the outcome of these claims can be made, and as no damage claim amount has been asserted by the claimants, we cannot reasonably estimate the potential impact of these claims. We intend to defend this case vigorously, and expect these claims to be resolved in our chapter 11 proceedings. The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position or results of operations.

12. CONCENTRATION OF CREDIT RISK:

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables. The Company's revenues related to natural gas and oil sales are derived principally from a diverse group of companies, including major energy companies, natural gas utilities, oil refiners, pipeline companies, local distribution companies, financial institutions and end-users in various industries.

Concentrations of credit risk with respect to receivables is limited due to the large number of customers and their dispersion across geographic areas. Commodity-based contracts may expose the Company to the credit risk of nonperformance by the counterparty to these contracts. This credit exposure to the Company is diversified primarily among as many as ten major investment grade institutions and will only be present if the reference price of natural gas established in those contracts is less than the prevailing market price of natural gas, from time to time.

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or oil sales, nor derivative settlements at December 31, 2016.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2016, the Company had one single customer that represented approximately 10% of its total revenues.

13. SUBSEQUENT EVENTS:

The Company has evaluated the period subsequent to December 31, 2016 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading, except as set forth below:

- On January 17, 2017, we filed a revised plan of reorganization and disclosure statement therefore. On February 8, 2017, we filed a further revised plan of reorganization and disclosure statement therefore. On February 13, 2017, we filed amendments and further revisions to the plan of reorganization we filed on February 8, 2017 and to the disclosure statement therefore. The Court approved our Disclosure Statement on February 13, 2017 and scheduled a hearing to consider confirmation of the Plan for March 14, 2017. On February 21, 2017, the Court signed an amended order approving our Disclosure Statement. The amended order: (1) approves the adequacy of our Disclosure Statement, (2) approves the solicitation and notice procedures related to confirmation of our plan of reorganization, (3) approves the forms of ballots and notices related thereto, (4) approves the rights offering procedures and matters related thereto, (5) schedules certain dates related to our plan confirmation process and Rights Offering, and (6) grants related relief. With respect to the Rights Offering, the amended order defines the "Subscription Commencement Date" as February 21, 2017. Accordingly, as will be reflected in the materials to be distributed in connection with the Rights Offering, the Plan Value under the PSA is $6.0 billion.

- On February 8, 2017, the Debtors obtained a commitment letter from Barclays, pursuant to which, in connection with the consummation of the Plan, Barclays has agreed to provide secured and unsecured financing in an aggregate amount of up to $2.4 billion, consisting of (i) a seven-year senior secured first lien term loan credit facility in an aggregate amount of $600.0 million, (ii) a five-year senior secured first lien revolving credit facility in an aggregate amount of $400.0 million and (iii) senior unsecured bridge loans under senior unsecured bridge facilities in an aggregate amount of up to $1.4 billion.
- As of January 19, 2017, the Backstop Approval Order was entered by the Bankruptcy Court and the Commitment Premium was fully earned by the Commitment Parties; the order being entered on January 19, 2017 satisfied one of the milestones in the Backstop Agreement. The Commitment Premium will be paid either in the form of new common stock at the Rights Offering Price, if the Plan is consummated as contemplated in the Plan Support Agreement, or in cash if the Backstop Agreement is terminated other than as a result of a material breach by the Commitment Parties. See Note 1 for further details.
- On April 4, 2016, we received a demand for payment and notice of enforcement from REX in connection with the transportation agreement related to the Rockies Express Pipeline, pursuant to which Rockies Express demanded payment from us of $303.2 million by April 20, 2016. On April 14, 2016, REX filed a lawsuit against us in Harris County, Texas alleging breach of contract and seeking damages related to the alleged breach. On August 26, 2016, REX filed a proof of claim with the Bankruptcy Court for $303.3 million. The Company objected to REX's proof of claim. On January 12, 2017, REX and the Company entered into a settlement agreement resolving REX's proof of claim. Pursuant to the settlement, we agreed to make a cash payment to REX of $150.0 million six months after the Company emerges from chapter 11, but no later than October 30, 2017, and to provide REX an allowed general unsecured claim under our Plan in that amount. Additionally, in connection with the settlement, we agreed to enter into, with REX, a new seven-year agreement, commencing December 1, 2019, for firm transportation service on the Rockies Express Pipeline, west-to-east, of 200,000 dekatherms per day at a rate of approximately $0.37 per dekatherm, or approximately $26.8 million annually. The settlement with REX has been submitted to the Bankruptcy Court for approval and will be implemented in connection with the plan of reorganization.
- The Company is a party, with Big West Oil, LLC ("Big West"), to several prepetition contracts (the "Crude Contracts") for the purchase and sale of crude oil. On April 26, 2016, Big West Oil LLC ("Big West") and the Company entered into a Temporary Suspension of Contracts and Interim Crude Oil Purchase and Sale Agreement ("Suspension Agreement"), pursuant to which the parties suspended performance under the prepetition contracts. On August 30, 2016, Big West filed a proof of claim with the Bankruptcy Court for $32.6 million. The Company objected to Big West's proof of claim. On January 20, 2017, Big West and the Company reached an agreement settling and resolving Big West's proof of claim. Pursuant to the settlement, we agreed to make a cash payment to Big West, within six months of our emergence from chapter 11, of $17.35 million, to provide Big West with an allowed general unsecured claim against all of the Ultra Entities in that amount and that all of our prepetition contracts with Big West, including the Suspension Agreement, would be rejected (with no additional damages other than the $17.35 million payment) in connection with our plan of reorganization. Additionally, in connection with the settlement, we and Big West agreed to enter into two new,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

two-year, contracts for the purchase and sale of crude oil we produce in Wyoming and Utah. The settlement with Big West has been submitted to the Bankruptcy Court for approval and will be implemented in connection with the plan of reorganization.

14. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2016				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$159,386	$146,591	$199,253	$ 215,861	$ 721,091
Operating expenses	126,868	94,746	99,788	99,313	420,715
Other income (expense), net:					
Interest expense (excludes contractual interest expense of $141.5 million for the year ended December 31, 2016)	(49,903)	(16,662)	—	—	(66,565)
Restructuring expenses	(5,579)	(1,569)	(28)	—	(7,176)
Contract settlement	—	—	—	(131,106)	(131,106)
Other income (expense), net	943	2,411	2,124	1,993	7,471
Total other (expense) income, net	(54,539)	(15,820)	2,096	(129,113)	(197,376)
Reorganization items, net	—	(22,183)	(3,109)	(22,211)	(47,503)
Income before income tax (benefit) provision	(22,021)	13,842	98,452	(34,776)	55,497
Income tax (benefit) provision	(190)	(160)	45	(349)	(654)
Net (loss) income	$ (21,831)	$ 14,002	$ 98,407	$ (34,427)	$ 56,151
Net income (loss) per common share — basic	$ (0.14)	$ 0.09	$ 0.64	$ (0.22)	$ 0.37
Net income (loss) per common share — fully diluted	$ (0.14)	$ 0.09	$ 0.64	$ (0.22)	$ 0.36

	2015				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$219,309	$207,998	$222,503	$ 189,301	$ 839,111
Gain (loss) on commodity derivatives	36,865	(3,646)	9,390	2	42,611
Operating expenses	189,347	188,483	195,339	207,452	780,621
Ceiling test and other impairments	—	—	—	3,144,899	3,144,899
Interest expense	42,668	42,619	43,137	43,494	171,918
Other income (expense), net	(992)	1,827	2,354	903	4,092
Income before income tax provision	23,167	(24,923)	(4,229)	(3,205,639)	(3,211,624)
Income tax provision	(2,022)	(250)	(1,133)	(999)	(4,404)
Net income	$ 25,189	$ (24,673)	$ (3,096)	$ (3,204,640)	$ (3,207,220)
Net income per common share — basic	$ 0.16	$ (0.16)	$ (0.02)	$ (20.91)	$ (20.94)
Net income per common share — fully diluted	$ 0.16	$ (0.16)	$ (0.02)	$ (20.91)	$ (20.94)

15. DISCLOSURE ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

The following information about the Company's oil and natural gas producing activities is presented in accordance with FASB ASC Topic 932, Oil and Gas Reserve Estimation and Disclosures:

A. OIL AND GAS RESERVES:

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Vice President — Development is primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, a Masters of Business Administration and is a licensed Professional Engineer with over 15 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The estimates of proved reserves and future net revenue as of December 31, 2016, are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The Company engaged Netherland, Sewell & Associates, Inc. ("NSAI"), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company's assets for the year ended December 31, 2016, 2015 and 2014 in this annual report. For the year ended December 31, 2013, the Company engaged NSAI to prepare the reserve estimates for all of the Company's assets in Wyoming and Pennsylvania in this annual report. Due to the timing of the closing of the acquisition in Utah in December 2013 relative to the timing of preparing annual corporate reserves, the Company's Reservoir Engineering Department prepared the proved reserve estimates for its Utah assets for the year ended December 31, 2013, which were prepared in accordance with the Company's internal controls and SEC regulations and represented less than 2% of estimated proved reserves as of December 31, 2013.

Our internal professional staff works closely with our independent engineers, NSAI, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as an Exhibit to this annual report.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. He graduated from graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (“EIA”) of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following unaudited tables as of December 31, 2016, 2015 and 2014 reflect estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2016, 2015 and 2014. All such reserves are located in the Green River Basin in Wyoming, the Uinta Basin in Utah and the Appalachian Basin of Pennsylvania.

B. *ANALYSES OF CHANGES IN PROVEN RESERVES:*

	United States		
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)
Reserves, December 31, 2013	34,119	3,409,742	—
Extensions, discoveries and additions	34,275	866,513	210
Sales	—	(239,290)	—
Acquisitions	9,381	1,345,964	21,740
Production	(3,409)	(228,517)	—
Revisions	(6,600)	(323,218)	43
Reserves, December 31, 2014	67,766	4,831,194	21,993
Extensions, discoveries and additions	166	17,415	3
Sales	—	—	—
Acquisitions	—	—	—
Production	(3,533)	(268,954)	—
Revisions	(42,224)	(2,243,375)	(12,156)
Reserves, December 31, 2015	22,175	2,336,280	9,840
Extensions, discoveries and additions	3,519	251,634	530
Sales	—	—	—
Acquisitions	—	—	—
Production	(2,912)	(264,278)	—
Revisions	(1,307)	(2,023)	(467)
Reserves, December 31, 2016	21,475	2,321,613	9,903

	United States		
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)
Proved:			
Developed	20,566	1,777,267	—
Undeveloped	13,553	1,632,475	—
Total Proved — 2013	34,119	3,409,742	—
Developed	28,481	2,245,004	9,118
Undeveloped	39,285	2,586,190	12,875
Total Proved — 2014	67,766	4,831,194	21,993
Developed	22,175	2,336,280	9,840
Undeveloped	—	—	—
Total Proved — 2015	22,175	2,336,280	9,840
Developed	21,475	2,321,613	9,903
Undeveloped	—	—	—
Total Proved — 2016	21,475	2,321,613	9,903

Changes in proved developed reserves: During 2016, substantially all of our extensions and discoveries in the proved developed category were attributable to wells drilled in 2016.

Changes in proved undeveloped reserves: As of December 31, 2016 and 2015, the Company did not include PUD reserves in its total proved reserve estimates due to uncertainty regarding its ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves.

NGLs: During 2014, the Company acquired contracts related to NGLs providing the opportunity to realize the benefit of the NGLs from the gas it produces beginning in 2017. These contracts provide for an annual election to process NGLs, and the Company elected not to process NGLs in 2017.

Development plan: The development plan underlying the Company's proved undeveloped reserves, if any, adopted each year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company's shareholders.

In addition, as a part of our internal controls for determining a plan to develop our proved reserves each year, we consider whether we have the financial capability to develop proved undeveloped reserves. This year, because substantial doubt exists about our ability to continue as a going concern, we lack the required degree of certainty that we have the ability to fund a development plan. Therefore, as of December 31, 2016, we did not book any PUD reserves. As of February 22, 2017, the Company has 5 rigs running in the Pinedale field (4 operated, 1 non-operated) and, subject to available capital, intends to continue drilling and completing wells. We expect to report PUD reserves in future filings if we determine that we have the financial capability to execute a development plan.

C. STANDARDIZED MEASURE:

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved reserves. Natural gas prices have fluctuated widely in recent years. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues at December 31, 2016, 2015 and 2014 was $2.07, $2.21 and $4.32 per Mcf, respectively, for natural gas, and $37.90, $42.36 and $80.62 per barrel, respectively, for oil and condensate. During 2014, the Company acquired contracts related to NGLs providing the opportunity to realize the benefit of the NGLs from the gas it produces beginning in 2017. These contracts provide for an annual election to process NGLs, and the Company elected not to process NGLs in 2017. For 2016 and 2015, the average sales price utilized for purposes of estimating the Company's proved reserves and future net revenues associated with NGLs was $19.17 and $20.61 per barrel, respectively. The prices utilized in the reserve report are based upon the average of prices in effect on the first day of the month for the preceding twelve month period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company’s proved reserves and the tax basis of proved properties and available operating loss carryovers.

	As of December 31,		
	2016	2015	2014
Future cash inflows	$ 5,812,234	$ 6,312,095	$27,331,391
Future production costs	(2,665,082)	(3,006,265)	(8,627,657)
Future development costs	(355,923)	(358,848)	(3,859,385)
Future income taxes	—	—	(3,898,355)
Future net cash flows	2,791,229	2,946,982	10,945,994
Discount at 10%	(1,100,283)	(1,081,333)	(5,712,511)
Standardized measure of discounted future net cash flows	$ 1,690,946	$ 1,865,649	$ 5,233,483

The estimate of future income taxes is based on the future net cash flows from proved reserves adjusted for the tax basis of the oil and gas properties but without consideration of general and administrative and interest expenses.

D. SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS:

	December 31,		
	2016	2015	2014
Standardized measure, beginning	$1,865,649	$ 5,233,483	$ 3,187,969
Net revisions of previous quantity estimates	(9,623)	(2,126,998)	(603,795)
Extensions, discoveries and other changes	209,603	15,254	1,787,643
Sales of reserves in place	—	—	(398,506)
Acquisition of reserves	—	—	2,552,491
Changes in future development costs	11,556	1,618,068	(1,013,652)
Sales of oil and gas, net of production costs	(454,725)	(550,879)	(949,389)
Net change in prices and production costs	(72,939)	(6,996,416)	1,010,052
Development costs incurred during the period that reduce future development costs	22,523	548,112	342,987
Accretion of discount	186,565	709,736	413,177
Net changes in production rates and other	(67,663)	1,551,413	(175,419)
Net change in income taxes	—	1,863,876	(920,075)
Aggregate changes	(174,703)	(3,367,834)	2,045,514
Standardized measure, ending	$1,690,946	$ 1,865,649	$ 5,233,483

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond the control of the Company. The reserve data and standardized measures set forth herein represent only estimates. Reserve

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

E. COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES:

	Years Ended December 31,		
	2016	2015	2014
United States			
Property Acquisitions:			
Unproved	$ 983	$ 13,845	$ 26,106
Proved	—	—	895,179
Exploration*	224,277	18,164	197,664
Development	44,300	461,458	382,984
Total	$269,560	$493,467	$1,501,933

* Exploration costs (as defined in Regulation S-X) includes costs spent on development of unproved reserves in the Pinedale Field.

F. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:

	Years Ended December 31,		
	2016	2015	2014
United States			
Oil and gas revenue	$ 721,091	$ 839,111	$1,230,020
Production expenses	(266,366)	(288,231)	(280,631)
Depletion and depreciation	(125,121)	(401,200)	(292,951)
Ceiling test and other impairments	—	(3,144,899)	—
Income tax benefit (expense)	83,112	(9,841)	3,736
Total	$ 412,716	$(3,005,060)	$ 660,174

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

G. CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:

	December 31,	
	2016	2015
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 10,752,642	$ 10,480,165
Less: accumulated depletion, depreciation and amortization	(9,742,176)	(9,629,020)
	1,010,466	851,145
Unproven Properties:		
	$ 1,010,466	$ 851,145

16. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of Ultra Petroleum Corp. (the "Parent Company"), which are included to provide additional information with respect to the Parent Company's results of operations, financial position and cash flows on a stand-alone basis:

CONDENSED STATEMENT OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
General and administrative expense	$ 650	$ 308	$ 261
Other income (expense):			
Interest expense (excludes contractual interest expense of $52.4 million for the year ended December 31, 2016)	(26,590)	(81,069)	(42,996)
Income (loss) from unconsolidated affiliates	157,450	(3,152,078)	558,634
Guarantee fee income	6,073	23,029	23,045
Other expense	(64,888)	(1,684)	(1,324)
Reorganization items, net	(15,827)	—	—
Income (loss) before income taxes	55,568	(3,212,110)	537,098
Income tax benefit	(583)	(4,890)	(5,753)
Net income (loss)	$ 56,151	$(3,207,220)	$542,851

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONDENSED BALANCE SHEET

	December 31, 2016	December 31, 2015
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,009	$ 523
Accounts receivable from related companies	29,939	64,542
Other current assets	2,100	5,150
Total current assets	35,048	70,215
Other non-current assets	—	24,197
Total assets	$ 35,048	$ 94,412
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ —	$ 1,283,232
Interest payable	—	14,166
Accrued and other current liabilities	47	—
Total current liabilities	47	1,297,398
Advances from unconsolidated affiliates	1,623,414	1,788,951
Total liabilities not subject to compromise	1,623,461	3,086,349
Liabilities subject to compromise	1,339,739	—
Total shareholders' deficit	(2,928,152)	(2,991,937)
Total liabilities and shareholders' equity	$ 35,048	$ 94,412

CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
Net cash (used in) operating activities	$(21,309)	$(101,277)	$ (35,818)
Investing Activities:			
Investment in subsidiaries	—	—	(850,000)
Dividends received	24,089	96,297	52,741
Net cash provided by (used in) investing activities	24,089	96,297	(797,259)
Financing activities:			
Proceeds from issuance of Senior Notes	—	—	850,000
Deferred financing costs	—	6	(13,245)
Repurchased shares/net share settlements	43	—	(6,471)
Shares re-issued from treasury	(337)	4,725	2,936
Net cash (used in) provided by financing activities	(294)	4,731	833,220
Increase (decrease) in cash during the period	2,486	(249)	143
Cash and cash equivalents, beginning of period	523	772	629
Cash and cash equivalents, end of period	$ 3,009	$ 523	$ 772

Item 9. ***Change in and Disagreements with Accountants on Accounting and Financial Disclosures.***

None.

Item 9A. ***Controls and Procedures.***

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included on page 60 of this form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2016 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Evaluation of Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Exchange Act. Based on that evaluation, our chief executive officer and our chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2016. The evaluation considered the procedures designed to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

Item 9B. ***Other Information.***

None.

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2016.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company's website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 400 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2016.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2016.

Item 13. ***Certain Relationships, Related Transactions and Director Independence.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2016.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2016.

Part IV

Item 15. ***Exhibits, Financial Statement Schedules.***

The following documents are filed as part of this report:

1. *Financial Statements:* See Item 8.

2. *Financial Statement Schedules:* None.

3. *Exhibits.* The following Exhibits are filed herewith pursuant to Rule 601 of the Regulation S-K or are incorporated by reference to previous filings.

Exhibit Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.2	By-Laws of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company's Report on Form 10-K/A for the period ended December 31, 2005)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
4.2	Form 8-A filed with the Securities and Exchange Commission on July 23, 2007.
4.3	Indenture dated December 12, 2013 between Ultra Petroleum Corp., as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Report on Form 8-K filed on December 12, 2013).
4.4	Indenture dated September 18, 2014 between Ultra Petroleum Corp., as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Report on Form 8-K filed on September 22, 2014).
10.1	Credit Agreement dated as of October 6, 2011 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 11, 2011).
10.2	Ultra Petroleum Corp. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-132443), filed with the SEC on March 15, 2006).
10.3	Ultra Petroleum Corp. 2000 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-13278), filed with the SEC on March 15, 2001).
10.4	Ultra Petroleum Corp. 1998 Stock Option Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-13342) filed with the SEC on April 2, 2001).
10.5	Employment Agreement between Ultra Petroleum Corp. and Michael D. Watford dated August 6, 2007 (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2007).
10.6	Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on March 6, 2008).
10.7	First Supplement dated March 5, 2009 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on March 5, 2009).
10.8	Second Supplement dated January 28, 2010 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on January 28, 2010).

Exhibit Number	Description
10.9	Third Supplement dated October 12, 2010 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 12, 2010).
10.10	Sale and Purchase Agreement dated October 18, 2013 between Axia Energy, LLC and UPL Three Rivers Holdings, LLC (incorporated by reference to Exhibit 1.1 of the Company's Report on Form 8-K filed on October 24, 2013).
10.11	Purchase and Sale Agreement dated August 13, 2014 between Ultra Petroleum Corp. and SWEPI LP (incorporated by reference from Exhibit 1.1 of the Company's Report on Form 8-K filed with the SEC on August 19, 2014).
10.12	Second Amendment to Employment Agreement dated February 24, 2016 but effective for all purposes as of February 16, 2016 by and between Ultra Petroleum Corp. and Michael D. Watford (incorporated by reference from Exhibit 10.17 of the Company's Report on Form 10-K filed with the SEC on February 29, 2016).
10.13	Ultra Petroleum Corp. 2016 Key Employee Incentive Plan adopted effective January 1, 2016 by Ultra Petroleum Corp. (incorporated by reference from Exhibit 10.18 of the Company's Report on Form 10-K filed with the SEC on February 29, 2016).
10.14	Limited Waiver Agreement, dated as of March 1, 2016, by and among Ultra Petroleum Corp., Ultra Resources, Inc., UP Energy Corporation, JPMorgan Chase Bank N.A., as administrative agent, and the Lenders party thereto (incorporated by reference from Exhibit 10.1 of the Company's Report on Form 8-K filed with the SEC on March 2, 2016).
10.15	Waiver and Amendment to Master Note Purchase Agreement, Notes and Supplement, dated as of March 1, 2016, by and among Ultra Resources, Inc. and the holders of the unsecured senior notes issued by Ultra Resources under the Master Note Purchase Agreement, dated as of March 6, 2008 (incorporated by reference from Exhibit 10.2 of the Company's Report on Form 8-K filed with the SEC on March 2, 2016).
10.16	Plan Support Agreement dated November 21, 2016, by and among Ultra Petroleum Corp. and the other Ultra Entities, on the one hand, and certain holders of common stock in Ultra Petroleum Corp. and debt securities issued by Ultra Petroleum Corp., on the other hand (incorporated by reference from Exhibit 10.1 of the Company's Report on Form 8-K filed with the SEC on November 22, 2016).
10.17	Backstop Commitment Agreement dated November 21, 2016, by and among Ultra Petroleum Corp. and the other Ultra Entities, on the one hand, and certain holders of common stock in Ultra Petroleum Corp. and debt securities issued by Ultra Petroleum Corp., on the other hand (incorporated by reference from Exhibit 10.2 of the Company's Report on Form 8-K filed with the SEC on November 22, 2016).
10.18	Commitment Letter dated as of February 8, 2017, by and among Ultra Resources, Inc. and Barclays Bank PLC (incorporated by reference from Exhibit 10.1 of the Company's Report on Form 8-K filed with the SEC on February 9, 2017).
10.19	First Amendment to Plan Support Agreement effective as of February 10, 2017, by and among Ultra Petroleum Corp. and the other Debtors, on the one hand, and certain holders of common stock in Ultra Petroleum Corp. and debt securities issued by Ultra Petroleum Corp., on the other hand (incorporated by reference from Exhibit 10.1 of the Company's Report on Form 8-K filed with the SEC on February 15, 2017).
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Description
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2016.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

SIGNATURES

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

ULTRA PETROLEUM CORP.

By: /s/ Michael D. Watford
Name: Michael D. Watford
Title: Chairman of the Board,
Chief Executive Officer, and President

Date: February 22, 2017

Pursuant to the requirements of the Securities and 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.

Signature	***Title***	***Date***
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 22, 2017
/s/ Garland R. Shaw Garland R. Shaw	Senior Vice President and Chief Financial Officer (principal financial officer)	February 22, 2017
/s/ Maree K. Delgado Maree K. Delgado	Corporate Controller (principal accounting officer)	February 22, 2017
/s/ W. Charles Helton W. Charles Helton	Director	February 22, 2017
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 22, 2017
/s/ Roger A. Brown Roger A. Brown	Director	February 22, 2017
/s/ Michael J. Keeffe Michael J. Keeffe	Director	February 22, 2017

Exhibit Index

Exhibit Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.2	By-Laws of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company's Report on Form 10-K/A for the period ended December 31, 2005)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
4.2	Form 8-A filed with the Securities and Exchange Commission on July 23, 2007.
4.3	Indenture dated December 12, 2013 between Ultra Petroleum Corp., as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Report on Form 8-K filed on December 12, 2013).
4.4	Indenture dated September 18, 2014 between Ultra Petroleum Corp., as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Report on Form 8-K filed on September 22, 2014).
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10.3	Ultra Petroleum Corp. 2000 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-13278), filed with the SEC on March 15, 2001).
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*23.2	Consent of Ernst & Young LLP.
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*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued a report, as of December 31, 2016, of the “Estimates of Reserves and Future Revenue to the Ultra Petroleum Corp. Interest in Certain Oil and Gas Properties located in Pennsylvania, Utah and Wyoming as of December 31, 2016” for Ultra Petroleum Corp. Netherland, Sewell & Associates, Inc. consents to the reference in Form 10-K to Netherland, Sewell & Associates, Inc.’s reserves report dated February 9, 2017, and to the incorporation by reference of our Firm’s name and report into Ultra’s previously filed Registration Statements on Form S-8 (File Nos. 333-13278; 333-132443; 333-202307), and Form S-3 (File No. 333-200916; 333-202256; 333-207028).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C. H. (Scott Rees) III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 20, 2017

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-13278) pertaining to the Ultra Petroleum Corp. 2000 Stock Incentive Plan,

(2) Registration Statement (Form S-8 No. 333-132443) pertaining to the Ultra Petroleum Corp. 2005 Stock Incentive Plan,

(3) Registration Statement (Form S-3 Shelf Registration No. 333-200916) of Ultra Petroleum Corp.,

(4) Registration Statement (Form S-3 Shelf Registration No. 333-202256) of Ultra Petroleum Corp.,

(5) Registration Statement (Form S-8 No. 333-202307) pertaining to the Ultra Petroleum Corp. 2015 Stock Incentive Plan,

(6) Registration Statement (Form S-3 Shelf Registration No. 333-207028) of Ultra Petroleum Corp.;

of our reports dated February 22, 2017, with respect to the consolidated financial statements of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) (which report expresses an unqualified opinion and includes an explanatory paragraph regarding going concern uncertainty) and the effectiveness of internal control over financial reporting of Ultra Petroleum Corp. and subsidiaries (Debtor-in-Possession) included in this Annual Report (Form 10-K) of Ultra Petroleum Corp. for the year ended December 31, 2016.

/s/ Ernst & Young LLP
Houston, Texas
February 22, 2017

Exhibit 31.1

CERTIFICATION

I, Michael D. Watford, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Michael D. Watford

Michael D. Watford,
Chairman, President and Chief Executive Officer (Principal Executive Officer)

Date: February 22, 2017

Exhibit 31.2

CERTIFICATION

I, Garland R. Shaw, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Garland R. Shaw

Garland R. Shaw,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 22, 2017

EXHIBIT 32.1

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL EXECUTIVE OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Michael D. Watford, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael D. Watford
Michael D. Watford,
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Dated: February 22, 2017

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Exhibit 32.2

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL FINANCIAL OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Garland R. Shaw, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garland R. Shaw
Garland R. Shaw,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Dated: February 22, 2017

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

February 9, 2017

Mr. W. Patrick Ash
Ultra Petroleum Corp.
116 Inverness Drive East, Suite 400
Englewood, Colorado 80112

Dear Mr. Ash:

In accordance with your request, we have estimated the proved developed reserves and future revenue, as of December 31, 2016, to the Ultra Petroleum Corp. (Ultra) interest in certain oil and gas properties located in Pennsylvania, Utah, and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Ultra. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities — Oil and Gas.* Definitions are presented immediately following this letter. This report has been prepared for Ultra's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Ultra interest in these properties, as of December 31, 2016, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	21,094.5	9,785.4	2,286,865.3	2,741,825.9	1,663,563.2
Proved Developed Non-Producing	380.8	117.7	34,747.9	49,403.5	27,382.8
Total Proved Developed	21,475.3	9,903.1	2,321,613.2	2,791,229.4	1,690,946.0

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved developed reserves. As requested, proved undeveloped, probable, and possible reserves that may exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Ultra's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Ultra's share of production taxes, ad valorem taxes, capital costs, abandonment costs, operating expenses, and payments to net profit interests but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2016. For oil and NGL volumes, the average spot price is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average regional

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1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

spot prices are adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $37.90 per barrel of oil, $19.17 per barrel of NGL, and $2.071 per MCF of gas. Average index prices along with the average realized prices for each area are shown in the following table:

	Oil/NGL				Gas		
		Average Spot Price	Average Realized Prices ($/Barrel)			Average Spot Price	Average Realized Price
Area	Pricing Index	($/Barrel)	Oil	NGL	Pricing Index	($/MMBTU)	($/MCF)
Pennsylvania	N/A	N/A	N/A	N/A	Leidy Hub	1.321	1.331
Utah	West Texas Intermediate	42.75	36.60	18.46	Northwest (south of Green River)	2.266	1.797
Wyoming	West Texas Intermediate	42.75	38.25	19.18	Kern River (Opal plant)	2.329	2.105

Operating costs used in this report are based on operating expense records of Ultra. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Ultra are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Ultra and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Ultra's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Ultra interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Ultra receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Ultra, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Ultra, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Sean A. Martin, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. Philip R. Hodgson, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Sean A. Martin
Sean A. Martin, P.E. 125354
Petroleum Engineer

Date Signed: February 9, 2017

By: /s/ Philip R. Hodgson
Philip R. Hodgson, P.G. 1314
Vice President

Date Signed: February 9, 2017

SAM:CDC

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities — Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

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

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

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves — Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves — Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.

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

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

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

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

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

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the 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.

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

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities — Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

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

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

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

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

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
>
> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.