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, 2015

☐ **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:

Title of Each Class	Name of Each Exchange on Which Registered
Common Shares, without par value	New York Stock Exchange

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (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 $1,918,659,990 as of June 30, 2015 (based on the last reported sales price of $12.52 of such stock on the New York Stock Exchange on such date).

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of February 9, 2016 was 153,255,989.

Documents incorporated by reference: The definitive Proxy Statement for the 2016 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2015, 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.
- ***MBOE*** — One thousand BOE.
- ***MMBOE*** — One million BOE.
- ***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 Investor Relations 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.

Liquidity and Ability to Continue as a Going Concern

As discussed under Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources, continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

As of February 29, 2016, the total outstanding principal amount of our debt obligations was $3.76 billion, consisting of the following:

- $450.0 million of unsecured senior notes due 2018 issued by us (the "2018 Notes");
- $850.0 million of unsecured senior notes due 2024 issued by us (the "2024 Notes");
- $999.0 million under the credit agreement between our wholly-owned subsidiary, Ultra Resources, Inc. ("Ultra Resources"), as the borrower, and JPMorgan Chase Bank, as the administrative agent (the "Credit Agreement") — Ultra Resources' obligations under the Credit Agreement are guaranteed by the Company and our wholly-owned subsidiary, UP Energy Corporation; and
- $1.46 billion in unsecured senior notes (the "Senior Notes") issued by Ultra Resources — Ultra Resources' obligations under the Senior Notes are guaranteed by the Company and UP Energy Corporation.

We recently borrowed $266.0 million under the Credit Agreement, which represented substantially all of the remaining undrawn amount under the Credit Agreement. These funds are intended to be used for general corporate purposes. As a result of the referenced borrowing, no material further extensions of credit are available under the Credit Agreement. As of February 29, 2016, the Company's cash on hand exceeds the amount recently borrowed under the Credit Agreement.

Our ability to continue as a "going concern" is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements, our ability to cure any defaults that occur under our debt agreements or to obtain waivers or forbearances with respect to any such defaults, and our ability to pay, retire, amend, replace or refinance our indebtedness as defaults occur or as interest and principal payments come due.

Our Credit Agreement contains covenants, including: a consolidated leverage covenant pursuant to which Ultra Resources must maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0; 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 to 1.0; and a covenant requiring us to deliver annual, audited, consolidated financial statements of the Company without a "going concern" or like qualification or exception. The Master Note Purchase Agreement governing our Senior Notes contains a consolidated leverage ratio covenant similar to the consolidated leverage ratio covenant in the Credit Agreement. The indentures governing our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage ratio covenant in the Credit Agreement and the Master Note Purchase Agreement at December 31, 2015 (the ratio was 3.37 to 1.00 at December 31, 2015). However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on the net present value of Ultra Resources' oil and gas properties and Ultra Resources' total funded consolidated debt at December 31, 2015, we expect to breach the PV-9 ratio in the Credit Agreement when we report whether or not we are in compliance with the covenant on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." As a result, we expect to be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the Credit Agreement lenders. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the interest charge coverage ratio in the indentures governing our 2018 Notes and our 2024 Notes at December 31, 2015 (the ratio was 3.30 to 1.00 at December 31, 2015). However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

We cannot provide any assurances that we will be able to comply with the covenants in our debt agreements or to make satisfactory alternative arrangements in the event we cannot do so. If we are unable to cure any such defaults, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness, we may consider or pursue various forms of negotiated restructurings of our debt obligations and/or asset sales under court supervision pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code or the Canadian Bankruptcy and Insolvency

Act, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us. Please read Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources for further discussion. Also, for additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A — Risk Factors.

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, 2015, Ultra owned interests in approximately 104,000 gross (68,000 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 9,000 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, 2015, the Company owned interests in approximately 150,000 gross (74,000 net) acres in Pennsylvania.

Mission and Strategy

In the past, Ultra's strategy has been to profitably grow an upstream oil and gas company for the long-term benefit of its shareholders by building a portfolio of high return investment opportunities, maintaining a disciplined approach to capital investment and maximizing earnings.

Due to the Company's current financial constraints, including potential defaults under our debt instruments, no available borrowing capacity under the Credit Agreement, constrained cash flow, negative working capital and limited to no other capital available beyond cash from operations and cash on hand, our current strategy is to (i) amend, replace, refinance or restructure our Credit Agreement and Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes; and/or (ii) secure additional capital through possible asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. However, we cannot provide any assurances that we will be successful in accomplishing any of these plans. See Item 1A — Risk Factors for a description of the possible consequences if we are not able to accomplish these plans.

Exploration and Production

As of December 31, 2015, the Company has no reportable 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 2015, the Company participated in the drilling of 206 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 $2.8 million per well average in the fourth quarter of 2015. The reduction in costs is attributable to drilling efficiencies and service cost reductions. The Company operates 87% of its production in the Pinedale field.

During 2016, 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 2015, the Company drilled 19 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. As a result, the Company has 22 wells drilled but not completed in its inventory. Ultra is the sole operator of the properties with a 100% working interest. At the end of 2015, approximately 77% of the Company's gross acreage holdings in Utah were held by production.

During 2016, Ultra does not plan to drill development wells on its Uinta Basin properties due to capital constraints and better returns expected in the Company's Pinedale assets. The Company plans to continue the waterflood pilot and may expand that project to other parts of the field.

Pennsylvania

During 2015, the Company did not drill any wells on its Pennsylvania properties. At the end of 2015, approximately 81% of the Company's gross acreage holdings in Pennsylvania were held by production. During 2016, the Company does not plan to drill any wells in Pennsylvania due to capital constraints and better returns expected in the Company's Pinedale assets.

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 and others 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 2015, 93% of the Company's production and 86% of its revenues, after realized gains or losses on hedging transactions, 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 Midwestern and Eastern regions 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. Under these agreements, the midstream service providers have routinely expanded 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, 2015.

	2012	2013	2014	2015	2016	2017	2018
NW Pipeline Corp. — Rocky Mountains	94%	96%	96%	93%	94%	94%	94%
Dominion Transmission Inc — Appalachia	100%	94%	74%	54%	63%	72%	78%

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 long-term contracts with refiners in the Salt Lake City, Utah area and is also shipped out of the area via rail from various rail loading facilities in the Salt Lake City region. 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 2015, 2014 and 2013, the quantities that the Company hedged for the succeeding twelve month periods represented 62%, 51% and less than 50%, 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 2015, the Company had no 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, 2015.

Environmental Matters

The U.S. Bureau of Land Management ("BLM") initiates preparation of an Environmental Impact Statement ("EIS") relating to potential natural gas development on federal lands in the Pinedale Anticline area in the Green River Basin of Wyoming. An EIS is required under the National Environmental Policy Act ("NEPA") for major federal actions significantly affecting the quality of the human environment and entails consideration of environmental consequences of a proposed action and its alternatives. Although the Company co-owns leases on state and privately owned lands in the vicinity of the Pinedale Anticline that do not fall under the federal jurisdiction of the BLM and are not subject to the EIS requirement, the area north of the Jonah field, including the Pinedale Anticline, which the EIS addresses, is where most of the Company's exploration and development is taking place. The BLM issues a Record of Decision ("ROD") with respect to a final EIS, which allows for surface disturbances for drilling and production activities within the area covered by the EIS, but does not authorize the drilling of particular wells. Ultra, therefore, must submit applications to the BLM's Pinedale field manager for permits and other required authorizations, such as rights-of-way for each specific well or particular pipeline location. In making its determination on whether to approve specific drilling or development activities, the BLM applies the requirements of the ROD.

The ROD imposes limits on drilling and completion activity and proposes mitigation guidelines, standard practices for industry activities and best management practices for sensitive areas. The Company cannot predict if or how these adjustments may affect permitting, development and compliance under the ROD. The BLM's field manager may also impose additional limitations and mitigation measures as are deemed reasonably necessary to mitigate the impact of drilling and production operations in the area.

To date, the Company has expended significant resources in order to satisfy applicable environmental laws and regulations in the Pinedale Anticline area and other areas of operation under the jurisdiction of the BLM. The Company's future costs of complying with these regulations may continue to be significant. Further, any additional limitations and mitigation measures could further increase production costs, delay exploration, development and production activities or curtail exploration, development and production activities altogether.

In August 1999, the BLM required an Environmental Assessment ("EA") for the potential increased density drilling in the Jonah field area. An EA is a more limited environmental study than that conducted under an EIS. The EA was required to address the potential environmental impacts of developing the Jonah field on a well density of two wells per 80-acre drilling and spacing unit as opposed to the one well per 80-acre drilling and spacing unit as was approved in the initial Jonah field EIS approved in 1998. The new EA was completed in June 2000. With the approval of this EA and the earlier approval by the WOGCC for drilling of two wells per 80-acre drilling and spacing unit, the Company was permitted to drill infill wells at this well density on the 2,160 gross (1,322 net) acres then owned by the Company in the Jonah field. Subsequently, various other operators have received approval for the drilling of increased density wells in pilot areas at well densities ranging from four wells per 80-acre drilling and spacing unit to sixteen wells per 80-acre drilling and spacing unit. Current spacing in the Jonah field is eight wells per 80-acre drilling and spacing unit (10-acre spacing) with several pilots testing spacing at 16 wells per 80-acre drilling and spacing unit (5-acre spacing).

The BLM prepared a new EIS covering the Jonah field to assess the impact of increased density development and define the parameters under which this increased density development will be allowed to proceed. The draft EIS was made available in February 2005 and the final ROD was issued on March 14, 2006. Key components of the ROD require an annual operations plan that includes all previous year activity including the number of wells drilled, total new surface disturbance by well pads, roads, and pipelines, and current status of all reclamation activity. Also required is a plan of development for the upcoming year reflecting the planned number of wells to be drilled and an estimate of new surface disturbance and reclamation activity. Other components include a drilling rig forecast, emission reduction report, annual water well monitoring reports, a three-year operational forecast and the use of flareless-completion technology to reduce noise, visual impacts and air emissions, including greenhouse gases as well as other monitoring and mitigation measures.

During the period from 2003 through year end 2011, Ultra and other operators in the Pinedale field received approval from the WOGCC to drill increased density and pilot project wells in several areas in the Lance Pool across the Pinedale field. During 2011, based on results of its 5-acre wells drilled in 2010, Ultra sought and obtained approval from the WOGCC to file for development of its acreage in Pinedale at a well density of 32 wells per 160-acre government quarter section (5-acre equivalent).

Ultra, Shell and Questar ("Proponents") submitted a development proposal for the Pinedale field, which includes broad application of operations principles being evaluated in the demonstration project area. The

Proponents entered into a memorandum of understanding with the BLM to commence the preparation of a supplemental EIS, or SEIS, for year-round access in the Pinedale field. The SEIS process included assessment of alternative considerations and mitigation requirements that were considered as alternatives, or in addition, to those included in the proposal. The proposal included commitments to reduce surface disturbance by utilizing fewer overall pads and drilling more directional wells than called for in the 2000 Pinedale Anticline Project Area (“PAPA”) ROD.

The final ROD (“2008 SEIS ROD”) was granted on September 9, 2008. The 2008 SEIS ROD allows, among other things, for full field development from no more than 600 well pads field-wide, as well as year-round development and delineation activity within big game (pronghorn and mule deer) and greater sage-grouse seasonal use areas. Further, the Proponents agreed to implement numerous individual mitigation components. These commitments include (i) the use of a full-field liquids gathering system, (ii) the use of advanced rig engine emission reduction technology by at least 80% of the Company’s 2005 rig emission levels, (iii) a mitigation and monitoring fund to address mitigation efforts to minimize impacts from energy development, and (iv) additional funding for ground water monitoring on the PAPA. Additionally, ten-year planning and annual meetings with BLM and appropriate state agencies will allow for proper community planning.

In July 2009, Ultra, along with Shell and Questar, were awarded the BLM’s 2009 Environmental Best Management Practices Award for Responsible Stewardship of Air Resources in the PAPA.

Regulation

Oil and Gas Regulation

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond the Company’s control. These factors may include, among other things, federal, state and local regulation of oil and natural gas production and transportation, including regulations governing environmental quality, pollution control and limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels.

Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- The location of wells;
- The method of drilling, completing and operating wells;
- The surface use and restoration of properties upon which wells are drilled;
- The rates of production or “allowables”;
- The venting or flaring of natural gas;
- Produced water and waste disposal;
- The plugging and abandoning of wells;
- The marketing, transportation and reporting of production; and
- Notice to surface owners and other third parties.

State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to the Company are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties and impose bonding requirements in order to drill and operate wells. The Wyoming Oil and Gas Conservation Commission, for example, recently voted unanimously to raise the state bonding requirements for oil and gas wells.

In addition, Pennsylvania's Environmental Quality Board recently approved rules governing surface operations at oil and gas wells. If these rules are approved and enacted by the Pennsylvania Independent Regulatory Review Commission and Legislative Committees and become effective, additional requirements may be imposed upon our operations. These requirements may include among other things, a ban on open-air waste storage pits, minimum distances between wells and schools and backgrounds, new requirements on monitoring well and new rules on cleaning up spills. More stringent standards were set for certain type of drillers (such as those who use deep horizontal drilling and those who use hydraulic fracturing).

The federal government has recently ended its decade-old prohibition of exports of crude oil produced in the lower 48 states of the U.S. It is too recent an event to determine the impact this regulatory change may have on our operations or our sales of crude oil. The general perception in the industry is that ending the prohibition of exports of crude oil produced in the U.S. will be positive for producers of U.S. crude oil.

Many states impose a production, ad valorem or severance tax with respect to the production and sale of oil and gas within their jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

The Company's sales of natural gas are affected by the availability, terms and costs of transportation both in the gathering systems that transport the natural gas from the wellhead to the interstate pipelines and in the interstate pipelines themselves. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has issued and implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis.

The Company's sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates.

The pipelines used to gather and transport natural gas being constructed by the Company and its partners are subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In August 2011, the PHMSA issued an Advance Notice of Proposed Rulemaking regarding pipeline safety, including questions regarding the modification of regulations applicable to gathering lines in rural areas. In October 2015, the PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and establish a timeline for inspections of affected pipelines following extreme weather events or natural disasters.

If the Company transports its crude oil by rail, such transportation is subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180 ("HMR"), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

If the Company conducts operations on federal, tribal or state lands, such operations must comply with numerous regulatory restrictions, including various operational requirements and restrictions, nondiscrimination statutes and royalty and related valuation requirements. In addition, some operations must be conducted pursuant to certain on-site security regulations, bonding requirements and applicable permits issued by the Bureau of Land Management ("BLM"), Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, and tribal or other applicable federal, state and/or Indian Tribal agencies.

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.

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 stringent federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. The EPA has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2014-2016 (and has solicited comments on continuing this initiative 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. Although such laws and regulations can increase the cost of planning, designing, installing and operating such facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them 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 Environmental Protection Agency (“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. 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.

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 but not at the federal level, as the federal Safe Drinking Water Act (“SDWA”) expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid). Congress has periodically considered legislation to amend the federal Safe Drinking Water Act 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 March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. The EPA released draft of the study in 2015. 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 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. 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. Among other things, the BLM rules impose new requirements to validate the protection of groundwater, disclosure of chemicals used in hydraulic fracturing and higher standards for the interim storage of recovered waste fluids from hydraulic fracturing. This rule is the subject of legal challenges and a federal district court in Wyoming has issued preliminary injunction temporarily delaying implementation of the BLM rule. 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, 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. 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 major federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an environmental assessment 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 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.

Air Emissions. The Company's operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. 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. Other federal and state laws designed to control hazardous (toxic) air pollutants might require installation of additional 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.

On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs under the Clean Air Act ("CAA"), and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators of oil and gas wells to reduce emissions of volatile organic compounds ("VOCs") during completions by either flaring using a completion combustion device or capturing any natural gas not delivered into gathering pipelines in a process commonly referred to as a "green completion." Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale. In addition, the rules establish new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. These rules may require changes to our operations, including possible installation of new equipment to control emissions which could result in additional significant costs. We continuously evaluate the effect of new rules on our business.

In 2015, the EPA proposed new rules limiting methane emissions from the oil and gas industry. The proposed rules, if adopted, would amend the air emissions rules for the oil and natural gas sources and natural gas processing and transmission sources to include new standards for methane. Simultaneously with the proposal of the methane rules, the EPA released a proposal soliciting comments on two alternatives for aggregating multiple surface sites into a single-source of air quality permitting purposes. Depending upon the alternative selected by the EPA, sites which currently would not require permitting under the Clean Air Act could require permits, an outcome that could result in costs and delays to our operations; however, given the present uncertainty regarding this rule, the extent and magnitude of that impact cannot be reliably or accurately estimated.

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.

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. 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. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation or the mere presence of threatened or endangered species could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. 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.

In addition to possible federal regulation, 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.

The Company believes that it is in substantial compliance with current applicable environmental 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, 2015, the Company had 167 full-time employees, including officers.

Item 1A. *Risk Factors.*

We have significant indebtedness. Our level of indebtedness could adversely affect our business, results of operations, and financial condition. If we are unable to comply with the financial and non-financial covenants governing our indebtedness or obtain waivers of any defaults that occur with respect to our indebtedness, or amend, replace or refinance any or all of the agreements governing our indebtedness and/or otherwise secure additional capital, we may be unable to continue as a going concern.

At February 29, 2016, we had the following obligations outstanding under our Credit Agreement (as defined in Note 5), our 2018 Notes (as defined in Note 5), our 2024 Notes (as defined in Note 5), and our Senior Notes (maturity dates exclude the effect of the default provisions described in Note 1 to the Consolidated Financial Statements):

- $999.0 million due October 2016 under the Credit Agreement;
- $450.0 million due December 2018 with respect to the 2018 Notes;
- $850.0 million due October 2024 with respect to the 2024 Notes; and
- $1.46 billion due between March 2016 and October 2025 with respect to the Senior Notes (see Note 5 for maturity details).

Our indebtedness affects our operations in several ways, including;

- a significant portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- the covenants contained in the agreements governing our indebtedness limit or in the future may limit our ability to borrow additional funds, pay dividends on our common stock, make certain investments and affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- we may be at a competitive disadvantage as compared to similar companies that have less debt; and
- future financing for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants or may not be available at all.

In addition, the terms of our indebtedness, including the covenants and the dates on which principal and interest payments on our indebtedness are due, increases the risk that we will be unable to continue as a going concern. To continue as a going concern over the next twelve months, we must make payments on our debt as they come due and comply with the covenants in the agreements governing our indebtedness or, if we fail to do so, to (i) negotiate and obtain waivers of or forbearances with respect to any defaults that occur with respect to our indebtedness, (ii) amend, replace, refinance or restructure any or all of the agreements governing our indebtedness, including our Credit Agreement, the Master Note Purchase Agreement (as defined in Note 5) related to the Senior Notes, and/or the indentures related to our 2018 Notes and our 2024 Notes, and/or (iii) otherwise secure additional capital. However, we cannot provide any assurances that we will be successful in accomplishing any of these plans, and if we were unable to do so or to otherwise obtain sufficient liquidity to repay the outstanding indebtedness and to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11") or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada.

The audit report we received with respect to our year-end 2015 consolidated financial statements contains an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." Our Credit Agreement requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. As a result, unless we obtain a waiver of this requirement, subject to a 30-day grace period, we will be in default under our Credit Agreement after we deliver our financial statements to the lenders under the Credit Agreement. Our failure to obtain a waiver of this requirement under the Credit Agreement within the applicable grace period could result in an acceleration of all of our outstanding debt obligations and the potential termination of the Pinedale Lease Agreement.

Under our Credit Agreement, we are required to deliver audited, consolidated financial statements without a "going concern" or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern," we will be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the lenders under the Credit Agreement. There is a 30-day grace period related to this covenant in the Credit Agreement. We are currently in discussions with these lenders regarding a waiver of this requirement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement before the expiration of the 30-day grace period, there will exist an event of default under the Credit Agreement.

If an event of default occurs under our Credit Agreement, the lenders could accelerate the loans outstanding under the Credit Agreement and deny any additional borrowing requests we might submit pursuant to the Credit Agreement. In addition, if the lenders under our Credit Agreement accelerate the loans outstanding under the Credit Agreement, we will then also be in default under the Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes. If we default under the Master Note Purchase Agreement, the holders of the Senior Notes could accelerate the Senior Notes. Likewise, if we default under the indentures, the holders of the 2018 Notes or the 2024 Notes could accelerate those notes.

If our lenders or our noteholders accelerate the payment of amounts outstanding under the Credit Agreement, the Senior Notes, the 2018 Notes or the 2024 Notes, respectively, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. We could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, we cannot provide any assurances that we will be successful in obtaining capital from such transactions on acceptable terms, or at all, and if we fail to obtain sufficient additional capital to repay the outstanding indebtedness and provide sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada.

In addition, if $100.0 million or more of our debt obligations are accelerated, the lessor under our Pinedale Lease Agreement could terminate the Pinedale Lease Agreement. A termination of the Pinedale Lease Agreement would significantly disrupt our ability to produce oil and gas from Pinedale field which would have a material adverse effect on our business, financial condition, results of operations, and cash flows.

There are covenants in the agreements governing our indebtedness. In many instances, a default under one of the agreements governing our indebtedness can, if not cured or waived, result in a default under certain of our other indebtedness agreements and/or the Pinedale Lease Agreement. A default on our obligations, an acceleration of our indebtedness by our lenders or noteholders, and/or a termination of the Pinedale Lease Agreement, as applicable, would have a material adverse impact on our business, financial condition, results of operations, cash flows, and the trading price of our securities.

Our 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, and 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 to 1.0. We are required to report whether we are in compliance with the consolidated leverage ratio after the end of each fiscal quarter, and we are required to report whether we are in compliance with the PV-9 ratio by April 1 after the end of each fiscal year.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage covenant at December 31, 2015 (the ratio was 3.37 to 1.00 at December 31, 2015). However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage ratio covenant for the trailing four fiscal quarters ended March 31, 2016. In addition, based on the net present value of our oil and gas properties and the total funded consolidated debt of the borrower under the Credit Agreement, each at December 31, 2015, we expect to breach the PV-9 ratio when we report whether we are in compliance on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The Master Note Purchase Agreement contains a consolidated leverage covenant similar to the consolidated leverage covenant in our Credit Agreement. Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with this covenant at December 31, 2015. However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The indentures related to our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio, pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to our total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness. Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with this covenant at December 31, 2015. However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

If our lenders or our noteholders accelerate the payment of amounts outstanding under the Credit Agreement, the Senior Notes, the 2018 Notes or the 2024 Notes, respectively, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. We could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, we cannot provide any assurances that we will be successful in obtaining capital from such transactions on acceptable terms, or at all, and if we were unable to obtain sufficient additional capital to repay the outstanding indebtedness and sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada.

In addition, if $100.0 million or more of our debt obligations are accelerated, the lessor under our Pinedale Lease Agreement could terminate the Pinedale Lease Agreement. A termination of the Pinedale Lease Agreement would significantly disrupt our ability to produce oil and gas from Pinedale field which would have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We have no borrowing capacity under our Credit Agreement. Unless we are able to successfully restructure our existing indebtedness, obtain waivers or forbearance from our existing lenders or otherwise raise significant capital, it is unlikely that we will be able to meet our obligations as they become due, and we may not be able to continue as a going concern.

Over the periods presented in the accompanying financial statements, our growth has been funded through a combination of borrowings under the agreements governing our indebtedness, the sale of assets and cash flows from operating activities. We currently have limited access to additional capital. We recently borrowed $266.0 million under our Credit Agreement, which represented substantially all of the remaining undrawn amount under the Credit Agreement.

The accompanying Consolidated Financial Statements have been prepared on a going concern basis which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. As a result of losses incurred and our current negative working capital, there is no assurance that the carrying amounts of assets will be realized or that liabilities will be settled for the amounts recorded. Unless we are able to successfully restructure our existing indebtedness, obtain waivers or forbearance from our existing lenders or otherwise raise significant additional capital, it is unlikely that we will be able to meet our obligations as they become due, and we may not be able to continue as a going concern. We can provide no assurance that we will be successful in our efforts to restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital.

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: our failure to comply with rules and regulations of Federal and state governmental agencies, including the United States Bureau of Land Management, the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; 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 may fail to comply with the standards for the continued listing of our common stock for trading on the New York Stock Exchange ("NYSE"). If we fail to comply with these continued listing standards, our common shares may be delisted from the NYSE which could result in reductions to the price of our common stock and would make it more difficult to trade our common stock.

Since August 2007, our common stock has been listed for trading on the NYSE. The continued listing of our common shares on the NYSE is subject to our compliance with a number of listing standards. To maintain compliance with these continued listing standards, we are required to maintain an average closing per share price of $1.00 or more over a consecutive 30 trading-day period. During the last two weeks of February 2016, our common stock, as reported on the NYSE, traded below $1.00 per share.

In addition to the above stock price criteria, we are considered to be below compliance if our average market capitalization over a consecutive 30 trading-day period is less than $50,000,000 and, at the same time our stockholders' equity is less than $50,000,000. Since the beginning of 2016, our market capitalization, as reported on the NYSE, has on occasion been below $50,000,000, and our stockholders' equity at December 31, 2015 is below $50,000,000.

For each of the above standards, the NYSE Listed Company Manual sets out rules and processes to cure non-compliance. For instance, upon approval from the NYSE, an issuer has 6 months to cure the listing standard related to stock price. Similarly, an issuer has 18 months to cure the listing standard related to global market capitalization.

There can be no assurance that we will continue to meet the continued listing standards of the NYSE. The delisting of our common shares from the NYSE could result in even further reductions in our share price, would substantially limit the liquidity of our common shares, and could materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NYSE could also have other negative results, including the potential loss of confidence by institutional investors.

Although we have substantial net operating losses and substantial federal income tax net operating loss carry-forwards, our ability to utilize our federal income tax net operating loss carry-forwards to offset any taxable income may be materially limited.

As noted in the financial statements included with this Form 10-K, we have substantial net operating losses. As a result, we also have substantial federal income tax net operating loss carry-forwards that we could utilize to offset taxable income in the future. An "ownership change" of the Company, as determined under Section 382 of the Internal Revenue Code, would limit, possibly substantially, the amount of our federal income tax net operating loss carry-forwards we can utilize to offset taxable income in any future taxable year. It is possible we will experience or have experienced one or more such ownership changes, whether because our equity interests are publicly-traded or in connection with our efforts to restructure our indebtedness. An ownership change would establish an annual limitation on the amount of federal income tax net operating loss carry-forwards existing prior to the change that we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our 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.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

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 93% of our total production for the year ended December 31, 2015 and represented 92% of our total proved reserves as of December 31, 2015. 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 7.3% of our total production for the year ended December 31, 2015 and represented 5% of our total proved reserves as of December 31, 2015. Crude oil prices declined substantially during 2015 and have remained very low during the first months of 2016. 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 2015 ranged from a high of $3.30 to a low of

$1.54 per MMBtu and the spot oil prices during 2015 ranged from a high of $61.43 to a low of $34.73 per Bbl. Thus far in 2016, commodity prices have continued to be depressed and volatile, with spot natural gas prices ranging from a high of $2.53 to a low of $1.81 per MMBtu and the spot oil prices ranging from a high of $36.76 to a low of $26.21 per Bbl through February 24, 2016. 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, like this year, 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.

We may seek protection from our creditors under Chapter 11 of the United States Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada, any of which may have a material adverse impact on our business, financial condition, results of operations, and cash flows, would have a material adverse impact on the trading price of our securities, and could place our shareholders at significant risk of losing all of their investment in our shares.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness in private transactions. However, if our attempts are unsuccessful or we are unable to complete such a restructuring on satisfactory terms, we may choose to pursue a filing under Chapter 11 or under the equivalent provisions of the Canadian Bankruptcy and Insolvency Act.

Seeking bankruptcy court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing on our business operations. 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, during the period of time we are involved in a bankruptcy proceeding, our customers and suppliers might lose confidence in our ability to reorganize our business successfully and may seek to establish alternative commercial relationships.

Additionally, all of our indebtedness is senior to the existing common stock in our capital structure. As a result, we believe that seeking bankruptcy court protection under a Chapter 11 proceeding (or the Canadian equivalent) could cause the shares of our existing common stock to be canceled, result in a limited recovery, if any, for shareholders of our common stock, and would place shareholders of our common stock at significant risk of losing all of their investment in our shares.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity issues and efforts to negotiate restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;
- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

During 2015 we recorded a $3.1 billion non-cash write-down of the carrying value of our proved oil and gas properties as a result of ceiling test limitations. If oil and natural gas prices stay at current levels or decrease further, we may be required to record additional write-downs of the carrying value of our oil and gas properties in the future.

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under the full cost method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. Discounted future net revenues are estimated using oil and natural gas spot prices based on the average price during the preceding 12-month period determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under SEC full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings.

For instance, during 2015, we recorded a $3.1 billion non-cash write-down of the carrying value of our proved oil and gas properties as a result of ceiling test limitations, which is reflected with the ceiling test and other impairments in our Consolidated Statements of Operations accompanying this report. Further impairments of the carrying value of our oil and gas properties may occur if commodity prices remain at current levels or continue to fall in the future. For example, not taking into account subsequent drilling results, production, changes in oil and natural gas prices, and changes in future development and operating costs, if the commodity price used to calculate our discounted future net revenues had been 10% lower than the price we used to perform our ceiling test calculation at December 31, 2015, the write-down we recorded would have been approximately $400.0 million larger.

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 other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous laws and regulations relating to environmental 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. 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. 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.

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 addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states 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. 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 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 but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities and has released a draft report; the final study has not yet been released. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. In past sessions, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the 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.

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 2016. 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 recently 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.

In addition, if $100.0 million or more of our debt obligations are accelerated, the lessor under our Pinedale Lease Agreement could terminate the Pinedale Lease Agreement. A termination of the Pinedale Lease Agreement would significantly disrupt our ability to produce oil and gas from Pinedale field which would have a material adverse effect on our business, financial condition, results of operations, and cash flows.

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.

In prior years, including as recently as 2014, transportation and refining capacity for the black wax crude oil produced from our properties in the Uinta Basin was limited. Although production in the Uinta Basin, including from our properties, is down substantially since 2014, if production of black wax crude oil from the Uinta Basin returns to levels achieved by the industry in 2014 and early 2015, our ability to sell our production and the profitability of our operations in the basin may be materially adversely impacted.

In December 2013, we acquired oil and gas properties located in the Uinta Basin, Utah. The crude oil these properties produce is known as black wax crude oil because it has high paraffin content. Due to this high paraffin content, transportation options are limited and more expensive than options available to other grades of crude oil. Most of the black wax crude oil produced in the Uinta Basin, including most of our black wax crude oil production, is transported by truck to refiners in the Salt Lake City, Utah area. The remainder of the production is transported by rail to markets outside of the Salt Lake City area. Future changes in regulations affecting transportation of crude oil by rail could increase the costs to the Company, and decrease the availability, of crude oil transportation by rail.

During 2014, market conditions and the unavailability of satisfactory transportation arrangements for this black wax crude oil hindered our access to markets, and there can be no assurance that we will be successful in securing profitable sales outlets for our Utah production in the future. The availability of a ready market depends on a number of factors, including the general demand for and supply of oil and the proximity of alternative reserves to pipelines, rail transportation and terminal facilities. Our ability to market our black wax crude production in the future will depend in substantial part on the availability and capacity of trucking and rail systems servicing the Uinta Basin and refineries capable of handling high paraffin crude, all of which are owned and operated by third parties. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of such markets or related transportation. Decreased access to oil markets or access to such markets on unacceptable terms could result in increased costs, decreased margins, decreased production, or other factors which could materially and adversely affect our business, financial condition and results of operations and operating cash flows.

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 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 2016.

As of December 31, 2015, the Company has no reportable estimated proved undeveloped reserves with respect to any of its properties because it has no reasonable expectation of financing their development. 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, 2015, the Company owned oil and natural gas leases totaling approximately 104,000 gross (68,000 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, 2015, approximately 32,000 gross (21,000 net) acres were developed, and 72,000 gross (47,000 net) acres were undeveloped. The developed portion represents 60% of the Company's total developed net acreage while the undeveloped portion represents approximately 32% of the Company's total undeveloped net acreage. The Company operates 90% of its acreage position in the Pinedale field and 87% of its production.

Lease maintenance costs in Wyoming were approximately $0.6 million for the year ended December 31, 2015. 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 2015, the Company participated in the drilling of 184 gross (132.3 net) productive development wells on the Green River Basin properties. At year-end 2015, there were 14 gross (9.9 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During 2015, the Company participated in the drilling of a total of 7 gross (3.8 net) productive exploratory wells on the Green River Basin properties. At December 31, 2015, there was 1 gross (0.3 net) additional exploratory well that commenced during the year that was 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.

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 2015, the Company initiated a project to merge the various data sets and reprocess the entire volume. That project should be complete during the second quarter of 2016.

Uinta Basin, Utah

As of December 31, 2015, the Company owned oil and natural gas leases covering 9,000 gross (9,000 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, 2015, approximately 4,000 gross (4,000 net) acres were developed, and 5,000 gross (5,000 net) acres were undeveloped. The developed portion represents 11% 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, 2015 were approximately $0.4 million. The Company owns approximately 7,000 gross (7,000 net) acres currently held by production or activities in Utah.

Development Wells. During 2015, the Company participated in the drilling of a total of 14 gross (14.0 net) productive development wells on the Utah properties. At December 31, 2015, 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 and thus a determination of productive capability could not be made at year-end.

Exploratory Wells. During 2015, the Company participated in the drilling of a total of 5 gross (5.0 net) productive exploratory wells on the Utah properties. At December 31, 2015, 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.

Waterflood. In 2015, the Company initiated a pilot waterflood project in the Utah asset. The Company plans to continue implementing this pilot in 2016 and to seek opportunities to expand waterflooding to nearby acreage.

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

Pennsylvania

As of December 31, 2015, the Company owned oil and gas leases covering 150,000 gross (74,000 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, 2015, approximately 20,000 gross (10,000 net) acres were developed, and 130,000 gross (64,000 net) acres were undeveloped. The Company's properties in Pennsylvania are outside operated.

Lease maintenance costs in Pennsylvania were approximately $0.5 million for the year ended December 31, 2015. The Company owns approximately 147,000 gross (73,000 net) acres currently held by production or activities in Pennsylvania.

Development Wells. During 2015, the Company did not participate in the drilling of any development wells on the Pennsylvania properties. At year-end 2015, 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.

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Exploratory Wells. During the year ended December 31, 2015, the Company did not participate in the drilling of any exploratory wells on the Pennsylvania properties. At December 31, 2015, 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, 2015, 2014, and 2013. 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, 2015, 2014 and 2013. As part of the SWEPI Transaction described in Note 3 of our consolidated financial statements, 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'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, 2015 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, 2015 reserve report. As of February 29, 2016, we are running three rigs in the Pinedale field (two 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 2016.

	December 31, 2015	December 31, 2014	December 31, 2013
Proved Developed Reserves			
Natural gas (MMcf)	2,336,280	2,245,004	1,777,267
Oil (MBbl)	22,175	28,481	20,566
Natural gas liquids (MBbl)	9,840	9,118	—
Proved Undeveloped Reserves			
Natural gas (MMcf)	—	2,586,190	1,632,475
Oil (MBbl)	—	39,285	13,553
Natural gas liquids (MBbl)	—	12,875	—
Total Proved Reserves (MMcfe)(1)	2,528,370	5,369,748	3,614,456
Estimated future net cash flows, before income tax	$ 2,946,982	$ 14,844,349	$ 8,306,171
Standardized measure of discounted future net cash flows, before income taxes(2)	$ 1,865,649	$ 7,097,359	$ 4,131,770
Future income tax	$ —	$ 1,863,876	$ 943,801
Standardized measure of discounted future net cash flows, after income tax	$ 1,865,649	$ 5,233,483	$ 3,187,969
Calculated average price(3)			
Gas ($/Mcf)	$ 2.21	$ 4.32	$ 3.51
Oil ($/Bbl)	$ 42.36	$ 80.62	$ 84.97
NGLs ($/Bbl)	$ 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, 2015, 2014 and 2013, 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, 2015, 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, 2015, the Company is not including 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.

As commodity prices fell during 2015, we revised our development plan and decreased our development pace. As of February 29, 2016, we are developing our properties at a substantially slower pace than was anticipated in our December 31, 2014 reserve report. 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, 2015, we transferred all of our proved undeveloped reserves to unproved status. As of February 29, 2016, the Company has 3 rigs running in the Pinedale field (2 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.

Changes in proved undeveloped reserves: Changes to the Company's PUD reserves during 2015 are summarized in the table below. These changes include updates to prior PUD reserves, the transfer of PUD reserves to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices and the uncertainty regarding our ability to continue as a going concern.

	MMcfe
Proved undeveloped reserves, December 31, 2014	2,899,150
Converted to proved developed	(516,227)
Proved undeveloped reserve extensions	—
Proved undeveloped reserve revisions	—
Proved undeveloped reserves transferred to unproven	(2,382,923)
Proved undeveloped reserves, December 31, 2015	—

***Conversions*:** In 2015, we converted 516.2 Bcfe of our proved undeveloped reserves to proved developed reserves, representing an 18% annual conversion rate (as determined by dividing the volumes of proved undeveloped reserves converted during 2015 by the total volumes of proved undeveloped reserves booked in our December 31, 2014 reserve report). We converted less than 20% of the proved undeveloped reserves booked in our December 31, 2014 reserve report during 2015 because, under the five-year development plan underlying our December 31, 2014 reserve report, we anticipated increasing our development activity each year. According to last year's five-year development plan, we anticipated converting approximately 16% of the year-end 2014 proved undeveloped reserves to proved developed reserves. Because we achieved an 18% annual conversion rate, we actually converted more of our proved undeveloped reserves during 2015 than were scheduled to be converted during the first year of the development plan.

Additions/Extensions: At December 31, 2015, the Company did not book any PUD reserves. Accordingly, there were no additions 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 in prior periods.

Transfers: At December 31, 2015, we transferred 2.4 Tcfe of proved undeveloped reserves to unproven categories. Because substantial doubt exists about our ability to continue as a going concern, in determining year-end 2015 reserve amounts, we concluded we lacked the required degree of certainty about our financial capability to fund a development program and the availability of capital that would be required to develop PUD reserves. As a result of our inability to meet the reasonable certainty criteria for recording these PUD reserves as prescribed under the SEC requirements, we did not any PUD locations in the December 31, 2015 reserve report.

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 Director – Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 14 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 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, 2015 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, 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 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. Robert C. Barg and Mr. Phillip R. Hodgson. Mr. Barg, a Licensed Professional Engineer in the State of Texas (No. 71658), has been practicing consulting petroleum engineering at NSAI since 1989 and has over 6 years of prior industry experience. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical 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,		
	2015	2014	2013
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	268,954	228,517	224,912
Oil (Bbl)	3,533	3,409	1,196
Total (Mcfe)	290,149	248,971	232,088
Revenues			
Natural gas sales	$696,730	$ 969,850	$824,266
Oil sales	142,381	260,170	109,138
Total revenues	$839,111	$1,230,020	$933,404
Lease Operating Expenses			
Lease operating expenses (a)	$106,906	$ 96,496	$ 68,106
Liquids gathering system operating lease expense	20,647	20,306	20,000
Severance/production taxes	72,774	103,898	72,398
Gathering	87,904	59,931	52,074
Total lease operating expenses	$288,231	$ 280,631	$212,578
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$ 3.14	$ 4.03	$ 3.57
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$ 2.59	$ 4.24	$ 3.66
Oil ($/Bbl), including realized gains (losses) on commodity derivatives)	$ 40.31	$ 76.47	$ 90.98
Oil ($/Bbl), excluding realized gains (losses) on commodity derivatives)	$ 40.31	$ 76.32	$ 91.25
Costs per Mcfe			
Lease operating expenses	$ 0.37	$ 0.39	$ 0.29
Liquids gathering system operating lease expense	$ 0.07	$ 0.08	$ 0.09
Severance/production taxes	$ 0.25	$ 0.42	$ 0.31
Gathering	$ 0.30	$ 0.24	$ 0.22
Transportation charges	$ 0.29	$ 0.31	$ 0.36
DD&A	$ 1.38	$ 1.18	$ 1.05
General & administrative	$ 0.03	$ 0.08	$ 0.10
Interest	$ 0.59	$ 0.51	$ 0.44
Total costs per Mcfe	$ 3.28	$ 3.21	$ 2.86

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, 2015:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Pinedale Field:			
Production (Mcfe)	261,498	184,479	159,714
Operating expenses	$253,214	$228,811	$179,686
Realized price, excluding hedges ($/Mcf)	$ 2.66	$ 4.56	$ 3.80
Realized price, including hedges ($/Mcf)	$ 3.24	$ 4.29	$ 3.67

(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, 2016, the Company has long-term natural gas delivery commitments of 5.1 MMMBtu in 2016 and 13.5 MMMBtu in 2017 under existing agreements. As of February 9, 2016, the Company has long-term crude oil delivery commitments of 3.4 MMBbls in 2016, 2.8 MMBbls in 2017, 1.1 MMBbls in 2018 and 0.2 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, 2015 the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas	2,734	1,805
Crude Oil	146	146
Total	2,880	1,951

* 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. At December 31, 2015, the Company had 206 net acres of leases in Pennsylvania, 13,402 net acres of leases in Colorado, 676 net acres of leases in Utah and no leases in Wyoming that expire in 2016. The Company has no immediate plans for further development of the Colorado leasehold in 2016, and plans to extend or renew few if any of the 2016 expiring leases in Pennsylvania. The Company expects to maintain all of the Utah leases 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.

As of December 31, 2015 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	32,000	21,000	72,000	47,000
Pennsylvania	20,000	10,000	130,000	64,000
Utah	4,000	4,000	5,000	5,000
Colorado	—	—	35,000	32,000
All States	56,000	35,000	242,000	148,000

Drilling Activities

For each of the three fiscal years ended December 31, 2015, 2014 and 2013 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	184.0	132.3	121.0	76.5	58.0	23.2
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	184.0	132.3	121.0	76.5	58.0	23.2

At year end, there were 14 gross (9.9 net) additional development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	7.0	3.8	25.0	13.4	55.0	31.1
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	7.0	3.8	25.0	13.4	55.0	31.1

At year end, there were 1 gross (0.3 net) additional exploratory wells that were either drilling or had operations suspended in the Pinedale field.

Utah

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	14.0	14.0	0.0	0.0	0.0	0.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	14.0	14.0	0.0	0.0	0.0	0.0

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

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	5.0	5.0	74.0	74.0	2.0	2.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.0	5.0	74.0	74.0	2.0	2.0

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

Pennsylvania

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	5.0	2.5	0.0	0.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	5.0	2.5	0.0	0.0

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

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.0	0.0	1.0	0.5	20.0	9.9
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	1.0	0.5	20.0	9.9

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 2015, 2014 or 2013. 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 2016.

Present Activities

Our present activities primarily involve continued production operations on our Pinedale field. Due to our current financial constraints, capital expenditures for development activities at these properties during 2016 have been limited. As of February 29, 2016, the Company has 3 rigs running in the Pinedale field (2 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.***

The Company is 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.***

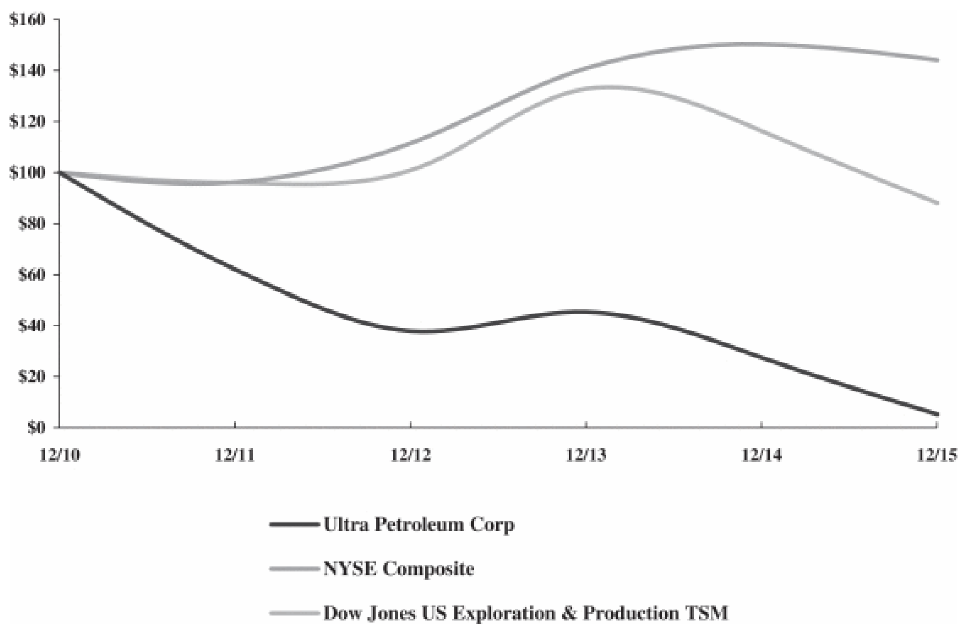
The Company's common shares trade on the New York Stock Exchange ("NYSE") under the symbol "UPL". The following table sets forth the high and low intra-day sales prices of the common shares for the periods indicated.

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

2014	High	Low
1st quarter	$27.26	$20.03
2nd quarter	$31.43	$25.95
3rd quarter	$29.77	$21.73
4th quarter	$24.98	$12.82

As of February 9, 2016, the last reported sales price of the common shares on the NYSE was $1.44 per share and there were approximately 332 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, 2010 through December 31, 2015.



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Item 6. *Selected Financial Data.*

The selected consolidated financial information presented below for the years ended December 31, 2015, 2014, 2013, 2012 and 2011 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 696,730	$ 969,850	$ 824,266	$ 695,733	$ 982,413
Oil sales	142,381	260,170	109,138	114,241	119,383
Total operating revenues	839,111	1,230,020	933,404	809,974	1,101,796
Expenses:					
Production expenses and taxes	288,231	280,631	212,578	184,229	205,363
Transportation charges	83,803	77,780	82,797	84,470	64,243
Depletion, depreciation and amortization	401,200	292,951	243,390	388,985	346,394
Ceiling test and other impairments	3,144,899	—	—	2,972,464	—
General and administrative	3,259	13,602	12,606	14,348	12,113
Stock compensation	4,128	5,467	9,767	10,756	13,919
Interest expense	171,918	126,157	101,486	88,180	63,156
Total operating expenses	4,097,438	796,588	662,624	3,743,432	705,188
Other:					
Gain (loss) on commodity derivatives	42,611	82,402	(46,754)	73,581	313,732
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553	—	—
Contract cancellation fees	—	—	—	(15,469)	—
Gain on sale of property	—	8,022	—	—	—
Litigation expense	(4,401)	—	—	—	—
Other income (expense), net	(2,060)	2,618	(357)	(1,765)	532
Total other income (expense), net	46,703	103,595	(36,558)	56,347	314,264
(Loss) income before income taxes	(3,211,624)	537,027	234,222	(2,877,111)	710,872
Income tax (benefit) provision	(4,404)	(5,824)	(3,616)	(700,213)	257,670
Net (loss) income	$(3,207,220)	$ 542,851	$ 237,838	$(2,176,898)	$ 453,202
Basic (Loss) Earnings per Share:					
Net (loss) income per common share — basic	$ (20.94)	$ 3.54	$ 1.55	$ (14.24)	$ 2.97
Fully Diluted (Loss) Earnings per Share:					
Net (loss) income per common share — fully diluted	$ (20.94)	$ 3.51	$ 1.54	$ (14.24)	$ 2.94
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 515,538	$ 712,584	$ 472,638	$ 654,825	$ 1,033,292
Investing activities	$ (512,757)	$(1,600,743)	$(1,093,519)	$ (577,223)	$(1,408,795)
Financing activities	$ (7,557)	$ 886,414	$ 618,624	$ (75,988)	$ 315,976
Balance Sheet Data:					
Cash and cash equivalents	$ 4,143	$ 8,919	$ 10,664	$ 12,921	$ 11,307
Working capital deficit	$(3,560,683)	$ (168,580)	$ (278,845)	$ (388,244)	$ (251,059)
Oil and gas properties	$ 851,145	$ 3,878,937	$ 2,421,611	$ 1,657,500	$ 4,189,148
Total assets	$ 971,486	$ 4,225,690	$ 2,785,319	$ 2,007,345	$ 4,869,705
Total debt	$ 3,390,000	$ 3,378,000	$ 2,470,000	$ 1,837,000	$ 1,903,000
Other long-term obligations	$ 165,784	$ 152,472	$ 91,932	$ 76,038	$ 67,008
Deferred income taxes, net	$ —	$ 992	$ —	$ —	$ 635,009
Total shareholders' (deficit) equity	$(2,991,937)	$ 211,660	$ (331,490)	$ (577,867)	$ 1,593,709

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, as part of the SWEPI Transaction, 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 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 2015 was $3.14 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2015, the average price realization for the Company's natural gas was $2.61 per Mcf, including realized gains and losses on commodity derivatives. The Company's average price realization for natural gas, excluding realized gains and losses on commodity derivatives, was $2.59 per Mcf and $2.33 per Mcf for the year and quarter ended December 31, 2015, respectively.

The average price realization for the Company's crude oil and condensate during 2015 was $40.31 per barrel. During the quarter ended December 31, 2015, the average price realization for the Company's crude oil and condensate was $35.51 per barrel.

Liquidity and Ability to Continue as a Going Concern

As discussed under Liquidity and Capital Resources, continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

As of February 29, 2016, the total outstanding principal amount of our debt obligations was $3.76 billion, consisting of the following:

- $450.0 million of 2018 Notes;
- $850.0 million of 2024 Notes;
- $999.0 million under the Credit Agreement; and
- $1.46 billion of Senior Notes.

We recently borrowed $266.0 million under the Credit Agreement, which represented substantially all of the remaining undrawn amount under the Credit Agreement. As a result, no material further extensions of credit are available under the Credit Agreement. As of February 29, 2016, the Company's cash on hand exceeds the amount recently borrowed under the Credit Agreement. These funds are intended to be used for general corporate purposes.

Our ability to continue as a "going concern" is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements, our ability to cure any defaults that occur under our debt agreements or to obtain waivers or forbearances with respect to any such defaults, and our ability to pay, retire, amend, replace or refinance our indebtedness as defaults occur or as interest and principal payments come due.

Our Credit Agreement contains covenants, including: a consolidated leverage covenant pursuant to which Ultra Resources must maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0; 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 to 1.0; and a covenant requiring us to deliver annual, audited, consolidated financial statements of the Company without a "going concern" or like qualification or exception. The Master Note Purchase Agreement governing our Senior Notes contains a consolidated leverage ratio covenant similar to the consolidated leverage ratio covenant in the Credit Agreement. The indentures governing our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage ratio covenant in the Credit Agreement and the Master Note Purchase Agreement at December 31, 2015 (the ratio was 3.37 to 1.00 at December 31, 2015). However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on the net present value of Ultra Resources' oil and gas properties and Ultra Resources' total funded consolidated debt at December 31, 2015, we expect to breach the PV-9 ratio in the Credit Agreement when we report whether or not we are in compliance with the covenant on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." As a result, we expect to be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the Credit Agreement lenders. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the interest charge coverage ratio in the indentures governing our 2018 Notes and our 2024 Notes at December 31, 2015. However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. If we are unable to cure any such default, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness or obligations, we may consider or pursue various forms of negotiated restructurings of our debt obligations and/or asset sales under court supervision pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us. Please read — Liquidity and Capital Resources for further discussion. Also, for additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A — Risk Factors.

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 2014 or 2013.

Deferred Financing Costs. Included in current assets at December 31, 2015 are costs associated with the issuance of our senior notes, revolving credit facility, 2018 Notes and 2024 Notes. The remaining unamortized issuance costs are being amortized over the life of the applicable debt or facility using the straight line method.

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 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, 2015. 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, 2015, 2014 and 2013 was $4.1 million, $5.5 million and $9.8 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. In February 2016, the FASB issued Accounting Standards Update ("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 also will 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 Dec. 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 November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* ("ASU No. 2015-17"). The guidance eliminates the requirement to present deferred tax assets and liabilities as current and noncurrent amounts in a classified balance sheet. The new standard requires deferred tax assets and liabilities to be classified as noncurrent. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period and may be applied either prospectively or retrospectively to all periods presented. The Company has elected early adoption of ASU No. 2015-17 and has applied these changes prospectively. The adoption of this guidance has no impact on our results of operations or cash flows. The reclassification of amounts from current to noncurrent affects presentation of our financial position. See Note 9 for additional information.

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 an amendment to U.S. GAAP to simplify the balance sheet presentation of the costs for issuing debt. The changes were adopted in ASU No. 2015-03, Interest — Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs (“ASU No. 2015-3”). Public companies will have to apply the amendments for reporting periods that start after December 15, 2015. The amendment requires adoption by revising the balance sheets for periods prior to the effective date, which makes it easier for investors to evaluate a company’s financial performance. The amendment to FASB ASC 835-30-45, Interest — Imputation of Interest, formerly Accounting Principles Board Opinion No. 21, means that the costs for issuing debt will appear on the balance sheet as a direct deduction of debt. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

In June 2015, the FASB issued a delay by one year of the revenue recognition standard adopted in June 2014. In June 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU No. 2014-09”), which amends the FASB ASC by adding new FASB ASC Topic 606, Revenue from Contracts with Customers, and superseding the revenue recognition requirements in FASB ASC 605, Revenue Recognition, and in most industry-specific topics. ASU No. 2014-09 provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. The new proposal related to ASU No. 2014-09 delays the application of the standard to reporting periods beginning after December 15, 2017 instead of December 15, 2016. The Company is still evaluating the impact of ASU No. 2014-09 on its financial position and results of operations.

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 beginning in 2016 and for interim reporting periods starting in the first quarter of 2017. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

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) on commodity derivatives	$ 146,801	$ (47,664)	n/a
Unrealized gain (loss) on commodity derivatives	$ (104,190)	$ 130,066	n/a
Total gain (loss) on commodity derivatives	$ 42,611	$ 82,402	n/a
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.

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Results of Operations — Year Ended December 31, 2014 vs. Year Ended December 31, 2013

	For the year ended December 31,		
	2014	2013	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	228,517	224,912	2%
Crude oil and condensate (Bbls)	3,409	1,196	185%
Total production (Mcfe)	248,971	232,088	7%
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$ 4.03	$ 3.57	13%
Natural gas ($/Mcf, excluding hedges)	$ 4.24	$ 3.66	16%
Crude oil and condensate ($/Bbl, incl realized hedges)	$ 76.47	$ 90.98	-16%
Crude oil and condensate ($/Bbl, excluding hedges)	$ 76.32	91.25	-16%
Revenues:			
Natural gas sales	$ 969,850	$ 824,266	18%
Oil sales	$ 260,170	$ 109,138	138%
Total operating revenues	$1,230,020	$ 933,404	32%
Derivatives:			
Realized (loss) gain on commodity derivatives	$ (47,664)	$ (20,878)	n/a
Unrealized (loss) on commodity derivatives	$ 130,066	$ (25,876)	n/a
Total (loss) gain on commodity derivatives	$ 82,402	$ (46,754)	n/a
Operating Costs and Expenses:			
Lease operating expenses	$ 96,496	$ 68,106	42%
Liquids gathering system operating lease expense	$ 20,306	$ 20,000	2%
Production taxes	$ 103,898	$ 72,398	44%
Gathering fees	$ 59,931	$ 52,074	15%
Transportation charges	$ 77,780	$ 82,797	-6%
Depletion, depreciation and amortization	$ 292,951	$ 243,390	20%
General and administrative expenses	$ 19,069	$ 22,373	-15%
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$ 0.39	$ 0.29	34%
Liquids gathering system operating lease expense	$ 0.08	$ 0.09	-11%
Production taxes	$ 0.42	$ 0.31	35%
Gathering fees	$ 0.24	$ 0.22	9%
Transportation charges	$ 0.31	$ 0.36	-14%
Depletion, depreciation and amortization	$ 1.18	$ 1.05	12%
General and administrative expenses	$ 0.08	$ 0.10	-20%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2014, production increased on a gas equivalent basis to 249.0 Bcfe from 232.1 Bcfe for the same period in 2013. The increase is primarily attributable to the acquisition of the Uinta Basin properties in December 2013, the SWEPI Transaction, which closed in September 2014 (See Note 13), and our drilling program, offset by expected production declines. Additionally, on an Mcfe basis, oil production increased from 3.1% of total production during the year ended December 31, 2013 to 8.2% of total production during the year ended December 31, 2014, primarily as a result of the acquisition of the Uinta Basin properties.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, increased to $4.03 per Mcf during the year ended December 31, 2014 as compared to

$3.57 per Mcf during 2013. During the year ended December 31, 2014, the Company's average price for natural gas was $4.24 per Mcf, excluding realized gains and losses on commodity derivatives, as compared to $3.66 per Mcf for the same period in 2013.

Commodity prices — oil. During the year ended December 31, 2014, the average price realization for the Company's oil decreased to $76.47 per barrel, including realized gains and losses on commodity derivatives compared to $90.98 per barrel during 2013. The Company's average price realization for oil during the year ended December 31, 2014 was $76.32 per barrel, excluding realized gains and losses on commodity derivatives. This compares with $91.25 per barrel during 2013. During the fourth quarter of 2014, oil prices declined to $57.44 per barrel as compared to $88.66 per barrel during the fourth quarter of 2013.

Revenues. Production from the recently acquired assets in Utah and Wyoming along with the increase in average natural gas prices, excluding the effects of commodity derivatives, largely contributed to a 32% increase in revenues for the year ended December 31, 2014 to $1.2 billion as compared to $933.4 million in 2013.

Operating Costs and Expenses:

Lease Operating Expense. LOE increased to $96.5 million for the year ended December 31, 2014 compared to $68.1 million during the same period in 2013 primarily due to the recently acquired assets in Utah. On a unit of production basis, LOE costs increased to $0.39 per Mcfe at December 31, 2014 compared to $0.29 per Mcfe at December 31, 2013 as a result of increased costs associated with oil production in 2014 realized from the oil producing assets acquired in Utah in December 2013.

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, 2014, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $20.3 million, or $0.08 per Mcfe compared with $20.0 million, or $0.09 per Mcfe in 2013.

Production Taxes. During the year ended December 31, 2014, production taxes were $103.9 million compared to $72.4 million during the same period in 2013, or $0.42 per Mcfe, compared to $0.31 per Mcfe. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 8.4% of revenues for the year ended 2014 and 7.8% for the same period in 2013. The increase in per unit taxes is primarily attributable to increased sales revenues as a result of increased natural gas prices, excluding the effects of commodity derivatives, during the year December 31, 2014 as compared to the same period in 2013.

Gathering Fees. Gathering fees increased to $59.9 million for the year ended December 31, 2014 compared to $52.1 million during the same period in 2013 largely due to production increases in Wyoming from drilling and the SWEPI Transaction. On a per unit basis, gathering fees were $0.24 per Mcfe for the year ended December 31, 2014 as compared to $0.22 per Mcfe for the period ended December 31, 2013.

Transportation Charges. The Company incurred firm transportation charges totaling $77.8 million for the year ended December 31, 2014 as compared to $82.8 million for the same period in 2013 in association with REX pipeline charges. Transportation charges decreased largely due to a refund 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 $0.31 per Mcfe (on total company volumes) for the year ended December 31, 2014 as compared to $0.36 per Mcfe for the same period in 2013 primarily due to increased production volumes during the year ended December 31, 2014.

Depletion, Depreciation and Amortization. DD&A expenses increased to $293.0 million during the year ended December 31, 2014 from $243.4 million for the same period in 2013, attributable to a higher depletion rate primarily related to the Utah acquisition. On a unit of production basis, DD&A increased to $1.18 per Mcfe at December 31, 2014 from $1.05 per Mcfe at December 31, 2013.

General and Administrative Expenses. General and administrative expenses decreased to $19.1 million for the period ended December 31, 2014 compared to $22.4 million for the same period in 2013. The decrease in general and administrative expenses is primarily attributable to decreased incentive compensation expense. On a per unit basis, general and administrative expenses decreased 20% to $0.08 per Mcfe for the year ended December 31, 2014 as compared to $0.10 per Mcfe for the year ended December 31, 2013.

Other Income and Expenses:

Interest Expense. Interest expense increased to $126.2 million during the period ended December 31, 2014 compared to $101.5 million during the same period in 2013 primarily as a result of higher average borrowings outstanding during the year ended December 31, 2014 and partially offset by increased amounts of capitalized interest for the year ended December 31, 2014. For the years ended December 31, 2014 and 2013, the Company capitalized $20.4 million and $2.0 million, respectively, in interest associated with unevaluated oil and gas properties that are excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service.

Deferred Gain on Sale of Liquids Gathering System. During the year ended December 31, 2014, the Company recognized $10.6 million compared with $10.6 million in 2013 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.

Gain on Sale of Property. During November 2014, the Company sold certain real property in El Paso County, Colorado for proceeds of $27.9 million, recognizing a gain of $8.0 million.

Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. During the year ended December 31, 2014, the Company recognized a gain of $82.4 million compared with a loss of $46.8 million related to commodity derivatives during the year ended December 31, 2013. Of this total, the Company recognized $47.7 million related to realized loss on commodity derivatives as compared to $20.9 million related to realized loss during the year ended December 31, 2013. 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 $130.1 million unrealized gain on commodity derivatives at December 31, 2014 as compared to a $25.9 million unrealized loss on commodity derivatives at December 31, 2013. The unrealized gain or loss on commodity derivatives represents the non-cash charge attributable to the change in the fair value of these derivative instruments.

Income from Continuing Operations:

Pretax Income. The Company recognized income before income taxes of $537.0 million for the year ended December 31, 2014 compared with $234.2 million for the same period in 2013. The increase in earnings is primarily related to increased revenues as a result of higher natural gas prices during 2014 and increased production related to the acquisition of the Uinta Basin properties in December 2013, the SWEPI Transaction in September 2014 and our drilling program.

Income Taxes. As a result of the tax effect of the non-cash ceiling test and other impairments, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset during the quarter ended June 30, 2012. The Company has recorded a valuation allowance against certain deferred tax assets of $161.5 million as of December 31, 2014. 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, 2014 was $5.8 million compared with an income tax benefit of $3.6 million for the year ended December 31, 2013.

Net Income. For the year ended December 31, 2014, the Company recognized net income of $542.9 million or $3.51 per diluted share as compared with net income of $237.8 million or $1.54 per diluted share for the same period in 2013. The increase in earnings is primarily related to increased revenues as a result of higher natural gas prices during 2014 and increased production related to the acquisition of the Uinta Basin properties in December 2013, the SWEPI Transaction in September 2014 and our drilling program.

LIQUIDITY AND CAPITAL RESOURCES

Overview. During the year ended December 31, 2015, the Company relied on cash provided by operations along with borrowings under the Credit Agreement to finance its capital expenditures. At December 31, 2015, the Company reported a cash position of $4.1 million compared to $8.9 million at December 31, 2014. At December 31, 2015, the Company had $630.0 million in outstanding borrowings and $370.0 million of available borrowing capacity under the Credit Agreement. In addition, the Company had $2.76 billion outstanding in senior notes (See Note 5).

The Company participated in 225 wells that were drilled to total depth and cased during 2015. For the year ended December 31, 2015, capital expenditures were $494.6 million ($494.0 million related to oil and gas exploration and development expenditures and $0.6 million related to other property costs).

Working Capital. The working capital deficit at December 31, 2015 was $3.6 billion compared to a deficit of $168.6 million at December 31, 2014. Other long-term obligations of $165.8 million at December 31, 2015 is comprised of items payable in more than one year, primarily related to production taxes and asset retirement obligations.

Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern. As a result, we have reclassified all of our total outstanding debt as short-term. A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

Maturities. At December 31, 2015, we have the following obligations outstanding under the Credit Agreement, the 2018 Notes, the 2024 Notes, and the Senior Notes (maturity dates exclude the effect of the default provisions described in Note 1):

- $630.0 million due October 2016 under the Credit Agreement;
- $450.0 million due December 2018 with respect to the 2018 Notes;
- $850.0 million due September 2024 with respect to the 2024 Notes; and
- $1.46 billion due between March 2016 and October 2025 with respect to the Senior Notes (see Note 8 for maturity details).

In addition, we anticipate the following significant near-term interest and maturity payments: (i) an approximately $40 million interest payment on March 1, 2016 under the Senior Notes; (ii) a $62 million maturity payment on March 1, 2016 under one series of the Senior Notes; and (iii) an approximately $26 million interest payment on April 1, 2016 under the 2024 Notes.

We are currently attempting to (i) amend, replace, refinance or restructure our Credit Agreement and Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes; and/or (ii) secure additional capital through possible asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. We may also seek additional sources of liquidity in an effort to secure sufficient cash to meet our operating and financing needs. These additional sources of liquidity could include asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. However, we cannot provide any assurances that we will be successful in accomplishing any of these plans.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. For additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A — Risk Factors.

Subsequent events. We recently borrowed $266.0 million under our Credit Agreement, which represented substantially all of the remaining undrawn amount under the Credit Agreement. As a result, no material further extensions of credit are available under our Credit Agreement. As of February 29, 2016, $999.0 million was outstanding under our Credit Agreement and the Company's cash on hand exceeded the amount recently borrowed under the Credit Agreement. These funds are intended to be used for general corporate purposes. For more information about the Credit Agreement, see Note 5.

2016 Capital Investment Plan. For 2016, our capital expenditures are expected to be $260.0 million, reflecting the current low commodity price environment. We expect to fund our 2016 capital expenditures budget through cash flows from operations and cash on hand. We expect to allocate nearly all of our 2016 budget to development activities in our Pinedale field. This reduction in planned capital expenditures will likely result in a slower rate of growth of our proved reserves through extensions and discoveries than previously forecasted as development is deferred to subsequent years.

Ultra Resources, Inc. —

Bank indebtedness. The Company (through its subsidiary, Ultra Resources, Inc.) is a party to a senior revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. (the "Credit Agreement"). The Credit Agreement provides an initial loan commitment of $1.0 billion, which may be increased up to $1.25 billion at the request of the borrower and with the consent of lenders who are willing to increase their loan commitments, provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016. With the majority (over 50%) lender consent, the term of the consenting lenders' commitments may be extended for up to two successive one-year periods at the Borrower's request. At December 31, 2015, the Company had $630.0 million in outstanding borrowings and $370.0 million of available borrowing capacity under the Credit Agreement.

The Credit Agreement is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Ultra Petroleum Corp. and UP Energy Corporation are holding companies that own no operating assets and have no significant operations independent of its subsidiary, Ultra Resources, Inc.

Loans under the Credit Agreement are unsecured and bear 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 Ultra Resources, Inc.'s consolidated leverage ratio (150 basis points as of December 31, 2015) 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 (250 basis points per annum as of December 31, 2015). The Company also pays commitment fees on the unused commitment under the facility based on a grid of its consolidated leverage ratio. For the year ended December 31, 2015, the Company incurred $1.7 million in commitment fees associated with its credit facility.

The Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as Ultra Resources, Inc.'s debt rating is below investment grade, the maintenance of an annual ratio of the net present value of Ultra Resources, Inc.'s oil and gas properties to total funded debt of no less than one and one half times to one. At December 31, 2015, the Company was in compliance with all of its debt covenants under the Credit Agreement except as described below in Covenants and Events of Default. (See Note 5).

Senior Notes. Ultra Resources also has outstanding $1.46 billion in principal amount of Senior Notes. Ultra Resources' Senior Notes rank pari passu with the Company's Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Ultra Petroleum Corp. and UP Energy Corporation are holding companies that own no operating assets and have no significant operations independent of its subsidiary, Ultra Resources, Inc.

The Senior Notes are pre-payable in whole or in part at any time following the payment of a make-whole premium and are subject to representations, warranties, covenants and events of default similar to those in the Credit Facility. At December 31, 2015, the Company was in compliance with all of its debt covenants under the Senior Notes. (See Note 5).

Ultra Petroleum Corp. —

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 Ultra Resources, Inc. The 2024 Notes are not guaranteed by the Company's subsidiaries and so are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. On and after October 1, 2019, the Company may redeem all or, from time to time, a part of the 2024 Notes at the following prices expressed as a percentage of principal amount of the 2024 Notes: (2019 —103.063%; 2020 —102.042%; 2021 —101.021%; and 2022 and thereafter — 100.000%). 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. In addition, the 2024 Notes contain events of default customary for a senior note financing. At December 31, 2015, the Company was in compliance with all of its debt covenants under the 2024 Notes. (See Note 5).

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 Ultra Resources, Inc. The 2018 Notes are not guaranteed by the Company's subsidiaries and so are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. On and after December 15, 2015, the Company may redeem all or, from time to time, a part of the 2018 Notes at the following prices expressed as a percentage of principal amount of the 2018 Notes: (2015 —102.875%; 2016 —101.438%; and 2017 and thereafter — 100.000%). 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. In addition, the 2018 Notes contain events of default customary for a senior note financing. At December 31, 2015, the Company was in compliance with all of its debt covenants under the Notes. (See Note 5).

Covenants and Events of Default

Our Credit Agreement contains covenants, including: a consolidated leverage covenant pursuant to which Ultra Resources must maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0; 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 to 1.0; and a covenant requiring us to deliver annual, audited, consolidated financial statements of the Company without a "going concern" or like qualification or exception. The Master Note Purchase Agreement governing our Senior Notes contains a consolidated leverage ratio covenant similar to the consolidated leverage ratio covenant in the Credit Agreement. The indentures governing our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage ratio covenant in the Credit Agreement and the Master Note Purchase Agreement at December 31, 2015 (the ratio was 3.37 to 1.00 at December 31, 2015). However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on the net present value of Ultra Resources' oil and gas properties and Ultra Resources' total funded consolidated debt at December 31, 2015, we expect to breach the PV-9 ratio in the Credit Agreement when we report whether or not we are in compliance with the covenant on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." As a result, we expect to be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the Credit Agreement lenders. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the interest charge coverage ratio in the indentures governing our 2018 Notes and our 2024 Notes at December 31, 2015. However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable. If we are unable to cure any such default, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness or obligations, we may consider or pursue various forms of negotiated restructurings of our debt obligations and/or asset sales under court supervision pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us.

Cash flows provided by (used in):

Operating Activities. During the year ended December 31, 2015, net cash provided by operating activities was $515.5 million, a 28% decrease from $712.6 million for the same period in 2014. 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 partially offset by increased natural gas and oil production during the year ended December 31, 2015 as compared to the same period in 2014.

Investing Activities. During the year ended December 31, 2015, net cash used in investing activities was $512.8 million as compared to $1.6 billion for the same period in 2014. The decrease in net cash used in investing activities is largely related to acquisition costs of $891.1 million associated with the SWEPI Transaction in 2014, decreased capital investments associated with the Company's drilling activities in 2015 as compared to 2014 and changes in the capital cost accrual. The Company accrues for exploration and development costs and construction of gathering systems in the period incurred, while payment may occur in a subsequent period.

Financing Activities. During the year ended December 31, 2015, net cash used in financing activities was $7.6 million as compared to net cash provided by financing activities of $886.4 million for the same period in 2014. The change in cash used in net financing activities is primarily due to decreased borrowings during 2015 as compared to 2014, primarily related to the SWEPI Transaction in 2014.

Outlook

Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and we are experiencing a period of financial distress. Substantial doubt exists that we will be able to continue as a going concern. We are working to amend, replace, refinance or restructure our debt agreements to alleviate the financial constraints we are experiencing. We may also work to secure additional capital through possible asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. We have reclassified all of our total outstanding debt as short-term. We have substantial principal maturities and interest payments coming due in the near future. If we fail to comply with the covenants or other restrictions in our debt agreements, or if we fail to pay maturing principal or interest that comes due as required under our debt agreements, all of our indebtedness (and any other contractual obligations to the extent linked to our indebtedness by reason of cross-default or cross-acceleration provisions) could become immediately due and payable.

We cannot provide any assurances that we will be able to comply with our debt agreements or make satisfactory alternative arrangements in the event we cannot do so. If we are unable to cure any such defaults, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness, we may seek to restructure our debt and other obligations pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us. For additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A—Risk Factors.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2015.

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Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2015:

	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)	$3,390,000	$3,390,000	$ —	$ —	$ —
Interest payments	168,635	168,635	—	—	—
Transportation contract (REX)(1)	368,100	101,199	201,845	65,056	—
Operating lease—Liquids Gathering System	248,232	20,686	41,372	41,372	144,802
Office space lease	7,782	1,395	2,699	2,119	1,569
Total contractual obligations	$4,182,749	$3,681,915	$245,916	$108,547	$146,371

(1) The values in the table represent the gross amounts that the Company is committed to pay; however, we record in our financial statements the Company's proportionate share of costs based on our revenue interest.

Outstanding debt and interest payments. Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern. As a result, we have reclassified our total outstanding debt as short-term.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. Please read Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources for further discussion. Also, for additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see Item 1A — Risk Factors.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. If satisfactory alternative arrangements are made, the total interest expense associated with our total outstanding debt is approximately $906.6 million at December 31, 2015; ($168.6 million in 2016; $287.6 million in total for 2017 and 2018; $184.5 million in total for 2019 and 2020; and $265.9 million due beyond five years.)

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from its properties and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas for a term of 10 years commencing in November 2009. During the first quarter of 2009, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018. The Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. The Company has the right, but not the obligation, to deliver its natural gas production into the REX pipeline, but has an obligation to pay reservation charges to REX in either event. On February 25, 2016, we received a letter from REX asserting that we were in default of the obligations under our transportation agreement for failing to provide adequate assurance of performance and for failing to timely pay invoice for transportation services provided by REX during January 2016. The letter also notified us that, according to REX, unless we remedy the alleged defaults of our obligations before the end of the 30-day notice period provided in the tariff, our transportation agreement will terminate automatically at the end of the notice period. Any termination of our transportation agreement on REX would not have a material adverse effect on our ability to market our production.

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, which is 0.19% at January 1, 2016) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease.

The audit report we received with respect to our year-end 2015 consolidated financial statements contains an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." Our Credit Agreement requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. As a result, we will be in default under our Credit Agreement on March 15, 2016 when we deliver our financial statements to the lenders under the Credit Agreement. Our failure to obtain a waiver of this requirement under the Credit Agreement within the applicable grace period could result in an acceleration of all of our outstanding debt obligations and the potential termination of the Pinedale Lease Agreement.

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 $7.8 million at December 31, 2015.

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, 2015, 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, 2015, 2014 and 2013:

	For the Year Ended December 31,		
Commodity Derivatives (000's):	**2015**	**2014**	**2013**
Realized gain (loss) on commodity derivatives-natural gas(1)	$ 146,801	$ (48,170)	$(20,552)
Realized gain (loss) on commodity derivatives-crude oil(1)	—	506	(326)
Unrealized gain (loss) on commodity derivatives(1)	(104,190)	130,066	(25,876)
Total gain (loss) on commodity derivatives	$ 42,611	$ 82,402	$(46,754)

(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, 2015.

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.

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2015 and 2014, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2015. 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. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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 Note 1 to the consolidated financial statements, the Company's maturing Credit Agreement and debt covenant violation raise 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 Note 1. 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.'s internal control over financial reporting as of December 31, 2015, 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 29, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 29, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2015, 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.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's 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. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, 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. as of December 31, 2015 and 2014, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 of Ultra Petroleum Corp. and our report dated February 29, 2016 expressed an unqualified opinion thereon that included an explanatory paragraph regarding Ultra Petroleum Corp.'s ability to continue as a going concern.

/s/ Ernst & Young LLP

Houston, Texas
February 29, 2016

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2015	2014	2013
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 696,730	$ 969,850	$ 824,266
Oil sales	142,381	260,170	109,138
Total operating revenues	839,111	1,230,020	933,404
Expenses:			
Lease operating expenses	106,906	96,496	68,106
Liquids gathering system operating lease expense	20,647	20,306	20,000
Production taxes	72,774	103,898	72,398
Gathering fees	87,904	59,931	52,074
Transportation charges	83,803	77,780	82,797
Depletion, depreciation and amortization	401,200	292,951	243,390
Ceiling test and other impairments	3,144,899	—	—
General and administrative	7,387	19,069	22,373
Total operating expenses	3,925,520	670,431	561,138
Operating (loss) income	(3,086,409)	559,589	372,266
Other income (expense), net:			
Interest expense	(171,918)	(126,157)	(101,486)
Gain (loss) on commodity derivatives	42,611	82,402	(46,754)
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553
Litigation expense	(4,401)	—	—
Gain on sale of property	—	8,022	—
Other (expense) income, net	(2,060)	2,618	(357)
Total other (expense) income, net	(125,215)	(22,562)	(138,044)
(Loss) income before income tax benefit	(3,211,624)	537,027	234,222
Income tax benefit	(4,404)	(5,824)	(3,616)
Net (loss) income	$(3,207,220)	$ 542,851	$ 237,838
Basic (Loss) Earnings per Share:			
Net (loss) income per common share — basic	$ (20.94)	$ 3.54	$ 1.55
Fully Diluted (Loss) Earnings per Share:			
Net (loss) income per common share — fully diluted	$ (20.94)	$ 3.51	$ 1.54
Weighted average common shares outstanding — basic	153,192	153,136	152,963
Weighted average common shares outstanding — fully diluted	153,192	154,694	154,426

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.

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ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,143	$ 8,919
Restricted cash	115	117
Oil and gas revenue receivable	61,881	111,915
Joint interest billing and other receivables	11,356	32,502
Derivative assets	—	104,190
Income tax receivable	5,150	6,246
Inventory	4,269	10,216
Deferred financing costs	20,477	—
Other current assets	3,270	3,033
Total current assets	110,661	277,138
Oil and gas properties, net, using the full cost method of accounting:		
Proven	851,145	3,636,643
Unproven properties not being amortized	—	242,294
Property, plant and equipment	8,844	12,186
Deferred income taxes	1	30,640
Other	835	26,789
Total assets	$ 971,486	$4,225,690
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 93,415	$ 77,580
Accrued liabilities	72,428	89,865
Production taxes payable	52,273	55,585
Current portion of long-term debt	3,390,000	100,000
Interest payable	42,657	46,098
Deferred income tax liabilities	—	30,638
Capital cost accrual	20,571	45,952
Total current liabilities	3,671,344	445,718
Long-term debt	—	3,278,000
Deferred income tax liabilities	—	992
Deferred gain on sale of liquids gathering system	126,295	136,848
Other long-term obligations	165,784	152,472
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding shares — 153,255,989 and 152,896,315, at December 31, 2015 and 2014, respectively	502,050	495,913
Treasury stock	(176)	(6,213)
Retained (loss)	(3,493,811)	(278,040)
Total shareholders' (deficit) equity	(2,991,937)	211,660
Total liabilities and shareholders' equity	$ 971,486	$4,225,690

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

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, 2012	152,930	$474,016	$(1,051,870)	$ (13)	$ (577,867)
Stock options exercised	1	11	—	—	11
Employee stock plan grants	347	700	—	—	700
Shares re-issued from treasury	—	(711)	(652)	1,363	—
Shares repurchased	(165)	—	—	(3,311)	(3,311)
Net share settlements	(122)	—	(2,118)	—	(2,118)
Fair value of employee stock plan grants	—	13,257	—	—	13,257
Net (loss)	—	—	237,838	—	237,838
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 repurchased	(332)	—	—	(6,472)	(6,472)
Shares re-issued from treasury	—	(770)	(1,450)	2,220	—
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)

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
Cash provided by (used in):	(Amounts in thousands of U.S. dollars)		
Operating activities:			
Net (loss) income for the period	$(3,207,220)	$ 542,851	$ 237,838
Adjustments to reconcile net (loss) income to cash provided by operating activities:			
Depletion, depreciation and amortization	401,200	292,951	243,390
Ceiling test and other impairments	3,144,899	—	—
Deferred and current non-cash income taxes	(990)	995	(6)
Unrealized loss (gain) on commodity derivatives	104,190	(130,066)	25,876
Deferred gain on sale of liquids gathering system	(10,553)	(10,553)	(10,553)
Gain on sale of property	—	(8,022)	—
Stock compensation	4,128	5,467	9,767
Other	9,217	4,569	2,252
Net changes in operating assets and liabilities:			
Restricted cash	2	2	2
Accounts receivable	65,132	(43,116)	16,565
Other current assets	(20,106)	(1,920)	1,180
Other non-current assets	21,112	284	277
Accounts payable	13,815	28,696	(1,400)
Accrued liabilities	1,655	(5,938)	(32,904)
Production taxes payable	(3,312)	15,115	(7,207)
Interest payable	(3,441)	14,233	1,772
Other long-term obligations	(5,770)	6,427	3,296
Current taxes payable/receivable	1,580	609	(17,507)
Net cash provided by operating activities	515,538	712,584	472,638
Investing Activities:			
Acquisition of oil and gas properties	3,964	(891,075)	(649,801)
Oil and gas property expenditures	(494,025)	(599,913)	(370,662)
Gathering system expenditures	—	(6,842)	(5,510)
Proceeds from sale of property	—	27,944	—
Proceeds from sale of liquids gathering system	—	—	(129)
Change in capital cost accrual	(25,380)	(125,577)	(65,975)
Inventory	3,235	175	(627)
Purchase of property, plant and equipment	(551)	(5,455)	(815)
Net cash used in investing activities	(512,757)	(1,600,743)	(1,093,519)
Financing activities:			
Borrowings on long-term debt	1,165,000	1,095,000	1,006,000
Payments on long-term debt	(1,153,000)	(1,037,000)	(823,000)
Proceeds from issuance of Senior Notes	—	850,000	450,000
Deferred financing costs	6	(13,245)	(8,958)
Repurchased shares/net share settlements	(2,514)	(9,111)	(5,429)
Payment of contingent consideration	(17,049)	—	—
Proceeds from exercise of options	—	770	11
Net cash (used in) provided by financing activities	(7,557)	886,414	618,624
(Decrease) in cash during the period	(4,776)	(1,745)	(2,257)
Cash and cash equivalents, beginning of period	8,919	10,664	12,921
Cash and cash equivalents, end of period	$ 4,143	$ 8,919	$ 10,664
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 169,867	$ 108,889	$ 99,542
Income taxes	$ —	$ 1,752	$ 13,843
Non-cash investing activities — oil and gas properties	$ —	$ 20,000	$ 12,651

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

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).

Ultra Petroleum Corp. (the "Company") is an independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties. The Company is incorporated under the laws of Yukon, Canada. The Company's principal business activities are in the Green River Basin of southwest Wyoming, the north-central Pennsylvania area of the Appalachian Basin and in the Uinta Basin in northeast Utah.

1. SIGNIFICANT ACCOUNTING POLICIES:

Liquidity and Ability to Continue as a Going Concern

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. Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

As of February 29, 2016, the total outstanding principal amount of our debt obligations was $3.76 billion, consisting of the following:

- $450.0 million of unsecured senior notes due 2018 issued by us (the "2018 Notes");
- $850.0 million of unsecured senior notes due 2024 issued by us (the "2024 Notes");
- $999.0 million under the credit agreement between our wholly-owned subsidiary, Ultra Resources, Inc. ("Ultra Resources"), as the borrower, and JPMorgan Chase Bank, as the administrative agent (the "Credit Agreement") — Ultra Resources' obligations under the Credit Agreement are guaranteed by the Company and UP Energy Corporation; and
- $1.46 billion in unsecured senior notes (the "Senior Notes") issued by Ultra Resources — Ultra Resources' obligations under the Senior Notes are guaranteed by the Company and UP Energy Corporation.

We recently borrowed $266.0 million under the Credit Agreement, which represented substantially all of the remaining undrawn amount under the Credit Agreement. As a result, no material further extensions of credit are available under the Credit Agreement. As of February 29, 2016, the Company's cash on hand exceeds the amount recently borrowed under the Credit Agreement. These funds are intended to be used for general corporate purposes.

Our ability to continue as a "going concern" is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements, our ability to cure any defaults that occur under our debt agreements or to obtain waivers or forbearances with respect to any such defaults, and our ability to pay, retire, amend, replace or refinance our indebtedness as defaults occur or as interest and principal payments come due.

Covenant Compliance. Our Credit Agreement contains covenants, including: a consolidated leverage covenant pursuant to which Ultra Resources must maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0; 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 to 1.0; and a covenant requiring us to deliver annual, audited, consolidated financial statements of the Company without a "going concern" or like qualification or exception. The Master Note Purchase Agreement governing our Senior Notes contains a consolidated leverage ratio covenant similar to the consolidated leverage ratio covenant in the Credit Agreement. The indentures governing our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage ratio covenant in the Credit Agreement and the Master Note Purchase Agreement at December 31, 2015. However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on the net present value of Ultra Resources' oil and gas properties and Ultra Resources' total funded consolidated debt at December 31, 2015, we expect to breach the PV-9 ratio in the Credit Agreement when we report whether or not we are in compliance with the covenant on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." As a result, we expect to be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the Credit Agreement lenders. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the interest charge coverage ratio in the indentures governing our 2018 Notes and our 2024 Notes at December 31, 2015. However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. If we are unable to cure any such default, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness or obligations, we may consider or pursue various forms of negotiated restructurings of our debt obligations and/or asset sales under court supervision pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code or the Canadian Bankruptcy and Insolvency Act, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us.

Maturities. At December 31, 2015, we have the following obligations outstanding under the Credit Agreement, the 2018 Notes, the 2024 Notes, and the Senior Notes (maturity dates exclude the effect of the default provisions described above):

- $630.0 million due October 2016 under the Credit Agreement;

- $450.0 million due December 2018 with respect to the 2018 Notes;
- $850.0 million due September 2024 with respect to the 2024 Notes; and
- $1.46 billion due between March 2016 and October 2025 with respect to the Senior Notes (see Note 8 for maturity details).

In addition, we anticipate the following significant near-term interest and maturity payments: (i) an approximately $40 million interest payment on March 1, 2016 under the Senior Notes; (ii) a $62 million maturity payment on March 1, 2016 under one series of the Senior Notes; and (iii) an approximately $26 million interest payment on April 1, 2016 under the 2024 Notes.

We are currently attempting to (i) amend, replace, refinance or restructure our Credit Agreement and Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes; and/or (ii) secure additional capital through possible asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. We may also seek additional sources of liquidity in an effort to secure sufficient cash to meet our operating and financing needs. However, we cannot provide any assurances that we will be successful in accomplishing any of these plans.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so.

(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.

(c) *Restricted cash:* Restricted cash 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. Previously, gathering system expenditures were recorded at cost and depreciated separately from proven oil and gas properties using the straight-line method due to the expectation that they would be used to transport production from probable and possible reserves, as well as from third parties. However, subsequent to the SWEPI Transaction, the Company’s remaining gathering systems are expected to only be used to transport the Company’s proved volumes and as a result, $91.8 million was transferred to proven oil and gas properties at September 30, 2014.

(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.

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. The Company did not have any write-downs related to the full cost ceiling limitation in 2014 or 2013.

(g) *Inventories:* At December 31, 2015 and 2014, inventory of $4.3 million and $10.2 million, respectively, primarily includes the cost of pipe and production equipment that will be utilized during the 2016 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 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. The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 7).

(i) *Deferred financing costs:* Included in current assets at December 31, 2015 are costs associated with the issuance of our senior notes, revolving credit facility, 2018 Notes and 2024 Notes. The remaining unamortized issuance costs are being amortized over the life of the applicable debt or facility using the straight line method.

(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.

The Company has recorded a valuation allowance against certain deferred tax assets of $1.3 billion as of December 31, 2015. Some or all of this valuation allowance may be reversed in future periods against future income.

(k) *Earnings (loss) per share:* Basic earnings (loss) per share is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted income (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.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	December 31, 2015	2014	2013
Net (loss) income	$(3,207,220)	$542,851	$237,838
Weighted average common shares outstanding during the period	153,192	153,136	152,963
Effect of dilutive instruments	—(1)	1,558	1,463
Weighted average common shares outstanding during the period including the effects of dilutive instruments	153,192	154,694	154,426
Net (loss) income per common share — basic	$ (20.94)	$ 3.54	$ 1.55
Net (loss) income per common share — fully diluted	$ (20.94)	$ 3.51	$ 1.54
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 ofthe common shares	—(1)	1,377	1,406

(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 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 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. Any amount received in excess of the Company's share of the volumes is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2015 and 2014, the Company had a net natural gas imbalance liability of $1.3 million and $3.0 million, respectively.

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.

(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, as well as on work in process relating to gathering systems that are not currently in service.

(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) *Recent accounting pronouncements:* In February 2016, the FASB issued Accounting Standards Update ("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 also will 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 Dec. 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 November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* ("ASU No. 2015-17"). The guidance eliminates the requirement to present deferred tax assets and liabilities as current and noncurrent amounts in a classified balance sheet. The new standard requires deferred tax assets and liabilities to be classified as noncurrent. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period and may be applied either prospectively or retrospectively to all periods presented. The Company has elected early adoption of ASU No. 2015-17 and has applied these changes prospectively. The adoption of this guidance has no impact on our results of operations or cash flows. The reclassification of amounts from current to noncurrent affects presentation of our financial position. See Note 9 for additional information.

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 an amendment to U.S. GAAP to simplify the balance sheet presentation of the costs for issuing debt. The changes were adopted in ASU No. 2015-03, *Interest — Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* ("ASU No. 2015-3"). Public companies will have to apply the amendments for reporting periods that start after December 15, 2015. The amendment requires adoption by revising the balance sheets for periods prior to the effective date, which makes it easier for investors to evaluate a company's financial performance. The amendment to FASB ASC 835-30-45, *Interest —Imputation of Interest,* formerly Accounting Principles Board Opinion No. 21, means that the costs for issuing debt will appear on the balance sheet as a direct deduction of debt. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

In June 2015, the FASB issued a delay by one year of the revenue recognition standard adopted in June 2014. In June 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU No. 2014-09"), which amends the FASB ASC by adding new FASB ASC Topic 606, *Revenue from Contracts with Customers*, and superseding the revenue recognition requirements in FASB ASC 605, *Revenue Recognition*, and in most industry-specific topics. ASU No. 2014-09 provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. The new proposal related to ASU No. 2014-09 delays the application of the standard to reporting periods beginning after December 15, 2017 instead of December 15, 2016. The Company is still evaluating the impact of ASU No. 2014-09 on its financial position and results of operations.

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 beginning in 2016 and for interim reporting periods starting in the first quarter of 2017. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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,	
	2015	2014
Asset retirement obligations at beginning of period	$127,240	$ 72,807
Accretion expense	9,122	6,571
Liabilities incurred	7,352	10,242
Liabilities acquired(1)	—	53,270
Liabilities divested(1)	—	(15,760)
Liabilities settled	(1,861)	(336)
Revisions of estimated liabilities	4,357	446
Asset retirement obligations at end of period	146,210	127,240
Less: current asset retirement obligations	(305)	(417)
Long-term asset retirement obligations	$145,905	$126,823

(1) On September 25, 2014, a wholly owned subsidiary of Ultra Petroleum Corp. completed the acquisition of all producing and non-producing properties in the Pinedale field in Sublette County, Wyoming in exchange for certain of the Company's producing and non-producing properties in Pennsylvania and a cash payment.

3. OIL AND GAS PROPERTIES:

	December 31, 2015	December 31, 2014
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs(1)	$10,480,165	$ 9,731,407
Less: Accumulated depletion, depreciation and amortization(2)	(9,629,020)	(6,094,764)
	851,145	3,636,643
Unproven Properties:		
Acquisition and exploration costs not being amortized(3), (4)	—	242,294
Net capitalized costs—oil and gas properties	$ 851,145	$ 3,878,937

On a unit basis, DD&A from continuing operations was $1.38, $1.18 and $1.05 per Mcfe for the years ended December 31, 2015, 2014 and 2013, respectively.

(1) On September 25, 2014, a wholly owned subsidiary of Ultra Petroleum Corp. completed the acquisition of all producing and non-producing properties in the Pinedale field in Sublette County, Wyoming in exchange for certain of the Company's producing and non-producing properties in Pennsylvania and a cash payment.

(2) 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.

(3) Interest is capitalized on the cost of unevaluated oil and natural gas properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service. For the years ended December 31, 2015 and 2014, total interest on outstanding debt was $185.0 million and $146.6 million, respectively, of which $13.1 million and $20.4 million, respectively, was capitalized on the cost of unevaluated oil and natural gas properties and work in process relating to gathering systems that are not currently in service.

(4) At December 31, 2015, all costs related to unevaluated properties that were previously excluded from capitalized costs being amortized have been impaired and transferred to the capitalized costs being amortized in the full cost pool.

Unproven Properties

At December 31, 2015, all costs related to unevaluated properties that were previously excluded from capitalized costs being amortized have been impaired or not considered significant and transferred to the capitalized costs being amortized in the full cost pool. Based on the quarterly evaluation of unproved leasehold costs, management determined that assumptions of future oil and gas production, commodity prices, operating and development costs indicate that the recorded carrying value of the unevaluated properties may not be recoverable.

	Total	2015	2014	2013	Prior
Acquisition costs	$ —	$(228,516)	$(191,184)	$419,700	$ —
Exploration costs	—	7,708	173	(7,881)	—
Capitalized interest	—	(21,486)	20,232	1,254	—
Unproven properties	$ —	$(242,294)	$(170,779)	$413,073	$ —

4. PROPERTY, PLANT AND EQUIPMENT:

	December 31,			
	2015			2014
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Computer equipment	2,797	(2,003)	794	917
Office equipment	520	(324)	196	57
Leasehold improvements	486	(219)	267	111
Land	4,637	—	4,637	5,778
Other	12,540	(9,590)	2,950	5,323
Property, plant and equipment, net	$20,980	$ (12,136)	$ 8,844	$12,186

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5. DEBT AND OTHER LONG-TERM LIABILITIES:

	December 31, 2015	December 31, 2014
Short-term debt:		
Senior Notes	$ 2,760,000	$ 100,000
Bank indebtedness	630,000	—
Long-term debt and other long-term liabilities:		
Bank indebtedness	—	518,000
Senior notes	—	2,760,000
Other long-term obligations	165,784	152,472
	$ 3,555,784	$ 3,530,472

Aggregate maturities of debt at December 31, 2015:(1)

2016	2017	2018	2019	2020	Beyond 5 years	Total
$3,390,000	$ —	$ —	$ —	$ —	$ —	$ 3,390,000

(1) Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern. As a result, we have reclassified all of our total outstanding debt as short-term.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. Please refer to Note 1 for further discussion.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

Ultra Resources, Inc. —

Bank indebtedness. The Company (through its subsidiary, Ultra Resources, Inc.) is a party to a senior revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. (the “Credit Agreement”). The Credit Agreement provides an initial loan commitment of $1.0 billion, which may be increased up to $1.25 billion at the request of the borrower and with the consent of lenders who are willing to increase their loan commitments, provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016. With the majority (over 50%) lender consent, the term of the consenting lenders’ commitments may be extended for up to two successive one-year periods at the Borrower’s request. At December 31, 2015, the Company had $630.0 million in outstanding borrowings and $370.0 million of available borrowing capacity under the Credit Agreement.

Loans under the Credit Agreement are unsecured and bear 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 Ultra Resources, Inc.’s consolidated leverage ratio (150 basis points as of December 31, 2015) 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 (250 basis points per annum as of December 31, 2015). The Company also pays commitment fees on the unused commitment under the facility based on a grid of its consolidated leverage ratio. For the year ended December 31, 2015, the Company incurred $1.7 million in commitment fees associated with its credit facility.

The Credit Agreement is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Ultra Petroleum Corp. and UP Energy Corporation are holding companies that own no operating assets and have no significant operations independent of its subsidiary, Ultra Resources, Inc.

The Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as Ultra Resources, Inc.'s debt rating is below investment grade, the maintenance of an annual ratio of the net present value of Ultra Resources, Inc.'s oil and gas properties to total funded debt of no less than one and one half times to one. At December 31, 2015, the Company was in compliance with all of its debt covenants under the Credit Agreement except as described below in Covenants and Events of Default.

Senior Notes. Ultra Resources also has outstanding $1.46 billion in principal amount of Senior Notes. Ultra Resources' Senior Notes rank pari passu with the Company's Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Ultra Petroleum Corp. and UP Energy Corporation are holding companies that own no operating assets and have no significant operations independent of its subsidiary, Ultra Resources, Inc.

The Senior Notes are pre-payable in whole or in part at any time following the payment of a make-whole premium and are subject to representations, warranties, covenants and events of default similar to those in the Credit Facility. At December 31, 2015, the Company was in compliance with all of its debt covenants under the Senior Notes.

Ultra Petroleum Corp. —

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 Ultra Resources, Inc. The 2024 Notes are not guaranteed by the Company's subsidiaries and so are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. On and after October 1, 2019, the Company may redeem all or, from time to time, a part of the 2024 Notes at the following prices expressed as a percentage of principal amount of the 2024 Notes: (2019 — 103.063%; 2020 — 102.042%; 2021 — 101.021%; and 2022 and thereafter — 100.000%). 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. In addition, the 2024 Notes contain events of default customary for a senior note financing. At December 31, 2015, the Company was in compliance with all of its debt covenants under 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 Ultra Resources, Inc. The 2018 Notes are not guaranteed by the Company's subsidiaries and so are structurally subordinated to the indebtedness and other obligations of the Company's subsidiaries. On and after December 15, 2015, the Company may redeem all or, from time to time, a part of the 2018 Notes at the following prices expressed as a percentage of principal amount of the 2018 Notes: (2015 — 102.875%; 2016 — 101.438%; and 2017 and thereafter — 100.000%). 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. In addition, the 2018 Notes contain events of default customary for a senior note financing. At December 31, 2015, the Company was in compliance with all of its debt covenants under the 2018 Notes.

Maturities

At December 31, 2015, we have the following obligations outstanding under the Credit Agreement, the 2018 Notes, the 2024 Notes, and the Senior Notes (maturity dates exclude the effect of the default provisions described in Note 1):

- $630.0 million due October 2016 under the Credit Agreement;
- $450.0 million due December 2018 with respect to the 2018 Notes;
- $850.0 million due September 2024 with respect to the 2024 Notes; and
- $1.46 billion due between March 2016 and October 2025 (see Note 8 for maturity details).

In addition, we anticipate the following significant near-term interest and maturity payments: (i) an approximately $40 million interest payment on March 1, 2016 under the Senior Notes; (ii) a $62 million maturity payment on March 1, 2016 under one series of the Senior Notes; and (iii) an approximately $26 million interest payment on April 1, 2016 under the 2024 Notes.

We are currently attempting to (i) amend, replace, refinance or restructure our Credit Agreement and Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes; and/or (ii) secure additional capital through possible asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps or any combination of these. We may also seek additional sources of liquidity in an effort to secure sufficient cash to meet our operating and financing needs. However, we cannot provide any assurances that we will be successful in accomplishing any of these plans.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. Please refer to Note 1 for further discussion.

Covenants and Events of Default

Our Credit Agreement contains covenants, including: a consolidated leverage covenant pursuant to which Ultra Resources must maintain a maximum ratio of its total funded consolidated debt to its trailing four fiscal quarters' EBITDAX of 3.5 to 1.0; 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 to 1.0; and a covenant requiring us to deliver annual, audited, consolidated financial statements of the

Company without a "going concern" or like qualification or exception. The Master Note Purchase Agreement governing our Senior Notes contains a consolidated leverage ratio covenant similar to the consolidated leverage ratio covenant in the Credit Agreement. The indentures governing our 2018 Notes and our 2024 Notes contain an interest charge coverage ratio pursuant to which we are required to maintain a minimum ratio of our trailing four fiscal quarters' consolidated EBITDA to total interest expense of no less than 2.25 to 1.00 as a precondition to our incurring additional indebtedness.

Based on our EBITDAX for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the consolidated leverage ratio covenant in the Credit Agreement and the Master Note Purchase Agreement at December 31, 2015. However, based on our estimates of forward commodity prices and our most recent production forecasts, we expect to breach the consolidated leverage covenant for the trailing four fiscal quarters ended March 31, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on the net present value of Ultra Resources' oil and gas properties and Ultra Resources' total funded consolidated debt at December 31, 2015, we expect to breach the PV-9 ratio in the Credit Agreement when we report whether or not we are in compliance with the covenant on April 1, 2016. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

The audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." As a result, we expect to be in default under the Credit Agreement on March 15, 2016 when we deliver our financial statements to the Credit Agreement lenders. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

Based on our EBITDA for the trailing four fiscal quarters ended December 31, 2015, we were in compliance with the interest charge coverage ratio in the indentures governing our 2018 Notes and our 2024 Notes at December 31, 2015. However, if commodity prices stay at or decline from recent levels or if we fail to develop new properties and operate our existing properties profitably or if our interest expense increases due to changes in the agreements governing our indebtedness or due to breaches of the covenants in the agreements governing our indebtedness, we may not be able to continue to comply with this covenant during the next twelve months. If we breach this covenant, our ability to incur additional indebtedness will be limited, or we may not be able to incur additional indebtedness at all.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable. If we are unable to cure any such default, or obtain a forbearance, a waiver or replacement financing, and those lenders, or other parties entitled to do so, accelerate the payment of such indebtedness or obligations, we may consider or pursue various forms of negotiated restructurings of our debt obligations and/or asset sales under court supervision pursuant to a voluntary bankruptcy filing under Chapter 11 of the U.S. Bankruptcy Code, which would have a material adverse effect on our business, financial condition, results of operations and cash flows. Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us.

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

6. SHARE BASED COMPENSATION:

The Company sponsors two share based compensation plans: the 2005 Stock Incentive Plan (the "2005 Plan") and the 2015 Stock Incentive Plan ("2015 Plan"; and together with the 2005 Plan, the "Plans"). The Plans are 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 2005 Plan was adopted by the Company's Board of Directors on January 1, 2005 and approved by the Company's shareholders on April 29, 2005. The 2015 Plan was adopted by the Company's Board of Directors on March 31, 2014 and approved by our shareholders on May 20, 2014. The purpose of the Plans 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 Plans permit 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 2005 Plan until December 31, 2014, unless terminated sooner by the Board of Directors, and under the 2015 Plan until December 31, 2024.

Valuation and Expense Information

	Year Ended December 31,		
	2015	2014	2013
Total cost of share-based payment plans	$6,137	$8,640	$13,957
Amounts capitalized in oil and gas properties and equipment	$2,009	$3,173	$ 4,190
Amounts charged against income, before income tax benefit	$4,128	$5,467	$ 9,767
Amount of related income tax benefit recognized in income before valuation allowances	$1,645	$2,285	$ 4,083

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2015, 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 (000's)	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)
Equity compensation plans approved by security holders	519	$ 58.98	4,555
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	519	$ 58.98	4,555

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, 2015:

	Number of Options (000's)	Weighted Average Exercise Price (US$)		
Balance, December 31, 2012	1,357	$16.97	to	$98.87
Forfeited	(110)	$25.68	to	$75.18
Exercised	(1)	$16.97	to	$16.97
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

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2015:

	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
$50.15 — $63.05	103	0.60	$ 55.37	$ —
$49.05 — $62.23	268	1.29	$ 53.96	$ —
$51.60 — $98.87	148	2.45	$ 70.61	$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $2.50 per share on December 31, 2015, 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, 2015.

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

	2015	2014	2013
Options forfeited during the year	$28.00	$24.40	$25.44

As of December 31, 2011, all options were fully vested; therefore, no options vested during the years ended December 31, 2015, 2014 or 2013. There were no stock options exercised during the years ended December 31, 2015 and 2014. The intrinsic value of stock options exercised during 2013 was immaterial.

At December 31, 2015, 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. For at least each of the last three years, the Company has 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 established since 2013, the Committee establishes time-based and performance-based measures at the beginning of each three-year performance period. For all LTIPs established prior to 2013, the Committee established performance-based measures at the beginning of each three-year performance period, but did not establish time-based measures. In addition, for all LTIPs established prior to 2013, the Committee approved payment of awards in shares of our common stock. For the LTIP awards in 2015, 2014 and 2013, the 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 awards.

Market-Based Measure (Total Shareholder Return):

LTIP awards granted to officers during 2015, 2014 and 2013, include 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	2013 LTIP
Volatility of common stock	40.1%	39.0%	39.2%
Average volatility of peer companies	46.5%	n/a	n/a
Average correlation coefficient of peer companies	0.454	n/a	n/a
Risk-free interest rate	1.02%	0.66%	0.40%

Stock-Based Compensation Cost:

For the year ended December 31, 2015, the Company recognized $2.9 million in pre-tax compensation expense related to the 2013, 2014 and 2015 LTIP awards. For the year ended December 31, 2014, the Company recognized $6.3 million in pre-tax compensation expense related to the 2012, 2013 and 2014 LTIP awards. For the year ended December 31, 2013, the Company recognized $6.9 million in pre-tax compensation expense related to the 2011, 2012 and 2013 LTIP awards. The amounts recognized during the year ended December 31, 2015 assumes that performance objectives between less than threshold and up to maximum are attained for the 2013 LTIP, 2014 LTIP and 2015 LTIP plans. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2015, for each of the three-year performance periods is expected to be approximately $8.0 million, $9.5 million, and $10.3 million related to the 2013, 2014 and 2015 LTIP awards of restricted stock units, respectively.

Based on the Company's achievement relative to the 2012 LTIP's performance-based measures, during the first quarter of 2015, the Compensation Committee approved payment of the 2012 LTIP in shares of the Company's stock. The payout of the 2012 LTIP was during the first quarter of 2015 and totaled $9.2 million (resulting in delivery of 232,626 net shares of our common stock to eligible participants in the 2012 LTIP).

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.

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, 2015, 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, 2015, 2014 and 2013:

	For the Year Ended December 31,		
Commodity Derivatives:	**2015**	**2014**	**2013**
Realized gain (loss) on commodity derivatives-natural gas(1)	$ 146,801	$ (48,170)	$(20,552)
Realized gain (loss) on commodity derivatives-crude oil(1)	—	506	(326)
Unrealized gain (loss) on commodity derivatives(1)	(104,190)	130,066	(25,876)
Total gain (loss) on commodity derivatives	$ 42,611	$ 82,402	$(46,754)

(1) Included in gain (loss) 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, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
5.45% Notes due March 2015, issued 2008	$ —	$ —	$ 100,000	$ 101,931
7.31% Notes due March 2016, issued 2009	62,000	63,604	62,000	65,027
4.98% Notes due January 2017, issued 2010	116,000	113,420	116,000	116,240
5.92% Notes due March 2018, issued 2008	200,000	191,985	200,000	203,738
5.75% Notes due December 2018, issued 2013	450,000	111,451	450,000	414,505
7.77% Notes due March 2019, issued 2009	173,000	174,488	173,000	187,105
5.50% Notes due January 2020, issued 2010	207,000	185,052	207,000	201,371
4.51% Notes due October 2020, issued 2010	315,000	258,520	315,000	283,335
5.60% Notes due January 2022, issued 2010	87,000	73,034	87,000	82,581
4.66% Notes due October 2022, issued 2010	35,000	25,558	35,000	30,476
6.125% Notes due October 2024, issued 2014	850,000	206,321	850,000	754,485
5.85% Notes due January 2025, issued 2010	90,000	70,756	90,000	83,876
4.91% Notes due October 2025, issued 2010	175,000	115,911	175,000	147,649
Credit Facility due October 2016	630,000	630,000	518,000	518,000
	$ 3,390,000	$ 2,220,100	$ 3,378,000	$ 3,190,319

9. INCOME TAXES:

(Loss) income before income tax benefit is as follows:

	Year Ended December 31,		
	2015	2014	2013
United States	$(3,249,590)	$505,689	$210,580
Foreign	37,966	31,338	23,642
Total	$(3,211,624)	$537,027	$234,222

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

	Year Ended December 31,		
	2015	2014	2013
Current tax:			
U.S. federal, state and local	$ —	$ (110)	$(8,491)
Foreign	(3,414)	(6,709)	4,881
Total current tax (benefit)	(3,414)	(6,819)	(3,610)
Deferred tax:			
Foreign	(990)	995	(6)
Total deferred tax (benefit) expense	(990)	995	(6)
Total income tax (benefit)	$(4,404)	$(5,824)	$(3,616)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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,		
	2015	2014	2013
Income tax (benefit) provision computed at the U.S. statutory rate	$(1,124,069)	$ 187,959	$ 81,978
State income tax (benefit) provision net of federal benefit	(12,998)	8,023	1,329
Valuation allowance	1,147,619	(199,038)	(81,923)
Tax effect of rate change	12,898	15,457	(2,871)
Foreign rate differential	(26,740)	(16,314)	(3,508)
Other, net	(1,114)	(1,911)	1,379
Total income tax (benefit)	$ (4,404)	$ (5,824)	$ (3,616)

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,	
	2015	2014
Deferred tax assets — current:		
Incentive compensation/other, net	—	6,150
	—	6,150
Net deferred tax assets — current	$ —	$ 6,150
Deferred tax liabilities — current:		
Derivative instruments, net	$ —	$ 36,788
Net deferred tax liabilities — current	$ —	$ 36,788
Net deferred tax liability — current	$ —	$ 30,638
Deferred tax assets — non-current:		
Property and equipment	776,504	—
Deferred gain	44,593	48,319
U.S. federal tax credit carryforwards	16,144	16,144
U.S. net operating loss carryforwards	319,673	147,336
U.S. state net operating loss carryforwards	61,919	53,654
Non-U.S. net operating loss carryforwards	9,142	—
Asset retirement obligations	51,815	45,039
Incentive compensation/other, net	28,711	19,142
	1,308,501	329,634
Valuation allowance	(1,307,076)	(161,480)
Net deferred tax assets — non-current	$ 1,425	$ 168,154
Deferred tax liabilities — non-current:		
Property and equipment	—	137,514
Other — non-US	1,424	—
Net non-current tax liabilities	$ 1,424	$ 137,514
Net non-current tax asset	$ 1	$ 30,640
Deferred tax liabilities — non-current:		
Other — non-US	—	992

As further described in Note 1, the Company adopted ASU 2015-17 on a prospective basis in 2015. As a result, the deferred tax assets and liabilities are classified as long-term in the Consolidated Balance Sheets as of December 31, 2015.

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. 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, 2015 and 2014, the Company recorded a valuation allowance against certain deferred tax assets of $1.3 billion and $161.5 million, respectively. Some or all of this valuation allowance may be reversed in future periods against future income. The Company's valuation allowance changed by $1.1 billion from December 31, 2014 to December 31, 2015. Of this amount, $1.1 billion reduced the Company's current year deferred tax benefit, and -$1.9 million was reflected through shareholders' equity.

As of December 31, 2015, the Company had approximately $14.1 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, none of which expire prior to 2017.

The Company generated a U.S. federal tax loss of $494.8 million and $213.0 million for the years ended December 31, 2015 and 2014, respectively. The total U.S. federal tax net operating loss of $913.4 million will be carried forward to offset taxable income generated in future years, and if unutilized, will expire between 2033 and 2035. The Company has Pennsylvania state tax net operating loss carry forwards of $920.7 million which will expire between 2031 and 2035. The Company has Utah state tax net operating loss carry forwards of $65.6 million which will expire between 2033 and 2035. 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 or has experienced an ownership change as determined by 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 generated a Canada Federal and Provincial tax loss of $61.3 million and $23.8 million for the years ended December 31, 2015 and 2014, respectively. To the extent possible, these losses will be carried back to offset taxable income generated in the prior three tax years. An income tax receivable of $5.2 million and $6.2 million has been recorded at December 31, 2015 and 2014, respectively, and is reflected as a reduction in 2015 and 2014 income tax expense in the Consolidated Statement of Operations. The remaining Canada Federal and Provincial tax loss of $33.9 million will be carried forward to offset taxable income generated in future years and will expire in 2035.

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, 2015.

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 2012 through 2015 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, $2.0 million and $1.6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

11. COMMITMENTS AND CONTINGENCIES:

Outstanding debt and interest payments. Continued low oil and natural gas prices during 2015 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern. As a result, we have reclassified our total outstanding debt as short-term.

Our ability to continue as a going concern is dependent on many factors, including, among other things, our ability to comply with the covenants in our existing debt agreements and amend or replace our debt agreements as they mature. Please refer to Note 1 for further discussion.

A failure by us to comply with our financial covenants or to comply with the other restrictions in our financing agreements may result in reduced borrowing capacity or an event of a default, causing our debt obligations under such financing agreements (and any other indebtedness or contractual obligations to the extent linked to it by reason of cross-default or cross-acceleration provisions) to potentially become immediately due and payable.

We cannot provide any assurances that we will be able to comply with the covenants or to make satisfactory alternative arrangements in the event we cannot do so. If satisfactory alternative arrangements are made, the total interest expense associated with our total outstanding debt is approximately $906.6 million at December 31, 2015; ($168.6 million in 2016; $287.6 million in total for 2017 and 2018; $184.5 million in total for 2019 and 2020; and $265.9 million due beyond five years.)

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas through November 2019. During the first quarter of 2009, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018.

The Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. The Company has the right, but not the obligation, to deliver its natural gas production into the REX pipeline, but has an obligation to pay reservation charges to REX in either event. On February 25, 2016, we received a letter from REX asserting that we were in default of the obligations under our transportation agreement for failing to provide adequate assurance of performance and for failing to timely pay invoice for transportation services provided by REX during January 2016. The letter also notified us that, according to REX, unless we remedy the alleged defaults of our obligations before the end of the 30-day notice period provided in the tariff, our transportation agreement will terminate automatically at the end of the notice period. Any termination of our transportation agreement on REX would not have a material adverse effect on our ability to market our production.

The Company currently projects that demand charges related to the remaining term of the contract will total approximately $368.1 million.

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 $248.2 million.

The audit report we received with respect to our year-end 2015 consolidated financial statements contains an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern." Our Credit Agreement requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. As a result, we will be in default under our Credit Agreement on March 15, 2016 when we deliver our financial statements to the lenders under the Credit Agreement. Our failure to obtain a waiver of this requirement under the Credit Agreement within the applicable grace period could result in an acceleration of all of our outstanding debt obligations and the potential termination of the Pinedale Lease Agreement.

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 $7.8 million at December 31, 2015; ($1.4 million in 2016; $1.4 million in 2017; $1.3 million in 2018; $1.2 million in 2019; and $1.0 million in 2020 with the remainder due beyond five years).

During the years ended December 31, 2015, 2014 and 2013, the Company recognized expense associated with its office leases in the amount of $1.3 million, $1.0 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, 2016, the Company has long-term natural gas delivery commitments of 5.1 MMMBtu in 2016 and 13.5 MMMBtu in 2017 under existing agreements. As of February 9, 2016, the Company has long-term crude oil delivery commitments of 3.4 MMBbls in 2016, 2.8 MMBbls in 2017, 1.1 MMBbls in 2018 and 0.2 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. 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, management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

12. CONCENTRATION OF CREDIT RISK:

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and commodity derivative contracts associated with the Company's hedging program. 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, 2015.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2015, the Company had no single customer that represented 10% or more of its total revenues.

13. SUBSEQUENT EVENTS:

We recently borrowed $266.0 million under our revolving credit facility, which represented substantially all of the remaining undrawn amount under the revolving credit facility. As a result, no material further extensions

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

of credit are available under our revolving credit facility. As of February 29, 2016, the Company's cash on hand exceeds the amount recently borrowed under the Credit Agreement. These funds are intended to be used for general corporate purposes. For more information about the Credit Facility, see Note 5.

Under our Credit Agreement, we are required to deliver audited, consolidated financial statements without a "going concern" or like qualification or explanation. Because the audit report prepared by our auditors with respect to the financial statements in this Form 10-K includes an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern," we are in default under our Credit Agreement. We are currently in discussions with the lenders under our Credit Agreement regarding a waiver of this requirement. If we do not obtain a waiver or other suitable relief from the lenders under the Credit Agreement before the expiration of the 30-day grace period, there will exist an event of default under the Credit Agreement. If an event of default occurs under our Credit Agreement, the lenders could accelerate the loans outstanding under the Credit Agreement. In addition, if the lenders under our Credit Agreement accelerate the loans outstanding under the Credit Agreement, we will then also be in default under the Master Note Purchase Agreement and the indentures related to our 2018 Notes and our 2024 Notes. If we default under the Master Note Purchase Agreement, the holders of the Senior Notes could accelerate the Senior Notes. Likewise, if we default under the indentures, the holders of the 2018 Notes or the 2024 Notes could accelerate those notes.

14. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2015				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$219,309	$ 207,998	$222,503	$ 189,301	$ 839,111
Gain (loss) on commodity derivatives	36,865	(3,646)	9,390	2	42,611
Expenses from continuing operations	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 (benefit)	23,167	(24,923)	(4,229)	(3,205,639)	(3,211,624)
Income tax provision (benefit)	(2,022)	(250)	(1,133)	(999)	(4,404)
Net income (loss)	$ 25,189	$ (24,673)	$ (3,096)	$ (3,204,640)	$ (3,207,220)
Net income (loss) per common share — basic	$ 0.16	$ (0.16)	$ (0.02)	$ (20.91)	$ (20.94)
Net income (loss) per common share — fully diluted	$ 0.16	$ (0.16)	$ (0.02)	$ (20.91)	$ (20.94)

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	2014				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$326,299	$ 296,063	$288,608	$319,050	$ 1,230,020
(Loss) gain on commodity derivatives	(45,273)	(15,102)	32,052	110,725	82,402
Expenses from continuing operations	154,829	150,850	169,669	195,083	670,431
Interest expense	27,068	27,294	29,599	42,196	126,157
Gain on sale of property	—	—	—	8,022	8,022
Other income (expense), net	2,590	2,688	2,582	5,311	13,171
Income before income tax provision (benefit)	101,719	105,505	123,974	205,829	537,027
Income tax provision (benefit)	4	(544)	(1,383)	(3,901)	(5,824)
Net income	$101,715	$ 106,049	$125,357	$209,730	$ 542,851
Net income per common share—basic	$ 0.66	$ 0.69	$ 0.82	$ 1.37	$ 3.54
Net income per common share—fully diluted	$ 0.66	$ 0.68	$ 0.81	$ 1.36	$ 3.51

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 Director — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 14 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, 2015, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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, 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 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. Robert C. Barg and Mr. Phillip R. Hodgson. Mr. Barg, a Licensed Professional Engineer in the State of Texas (No. 71658), has been practicing consulting petroleum engineering at NSAI since 1989 and has over 6 years of prior industry experience. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical 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, 2015, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following unaudited tables as of December 31, 2015, 2014, and 2013 reflect estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2015, 2014 and 2013. 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, 2012	18,137	2,966,445	—
Extensions, discoveries and additions	11,329	1,409,528	—
Acquistions	10,114	—	—
Production	(1,196)	(224,912)	—
Revisions	(4,265)	(741,319)	—
Reserves, December 31, 2013	34,119	3,409,742	—
Extensions, discoveries and additions	34,275	866,513	210
Sales	—	(239,290)	—
Acquistions	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	—	—	—
Acquistions	—	—	—
Production	(3,533)	(268,954)	—
Revisions	(42,224)	(2,243,375)	(12,156)
Reserves, December 31, 2015	22,175	2,336,280	9,840

	United States		
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)
Proved:			
Developed	10,531	1,820,994	—
Undeveloped	7,606	1,145,451	—
Total Proved — 2012	18,137	2,966,445	—
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

Changes in proved developed reserves: During 2015, substantially all of our extensions and discoveries in the proved developed category were attributable to wells drilled in 2015.

Changes in proved undeveloped reserves: In 2015, the Company converted 516.2 Bcfe of proved undeveloped reserves to proved developed reserves, representing an 18% annual conversion rate. At December 31, 2015, the Company transferred 2.4 Tcfe of proved undeveloped reserves to unproven categories. Because substantial doubt exists about our ability to continue as a going concern, in determining year-end 2015 reserve amounts, we concluded we lacked the required degree of certainty about our financial capability to fund a development program and the availability of capital that would be required to develop PUD reserves. As a result of our inability to meet the reasonable certainty criteria for recording these PUD reserves as prescribed under the SEC requirements, we did not book any PUD locations in the December 31, 2015 reserve report.

Of the 5.0 Tcfe of total proved reserves booked in the reserve report included in our year-end 2011 Form 10-K, we concluded that 106 Bcfe of the proved undeveloped reserves attributable to locations in Pennsylvania should not have been booked due to uncertainty regarding the future development of those reserves. These reserves were not material and this change to the year-end 2011 reserve report did not have a material impact on our financial statements for year-end 2011 or any subsequent year.

NGLs: As part of the SWEPI Transaction, 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.

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.

As commodity prices fell during 2015, we revised our development plan and decreased our development pace. As of February 29, 2016, we are developing our properties at a substantially slower pace than was anticipated in our December 31, 2014 reserve report. 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, 2015, we transferred all of our proved undeveloped reserves to unproved status. As of February 29, 2016, the Company has 3 rigs running in the Pinedale field (2 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, 2015, 2014 and 2013 was \$2.21, \$4.32 and \$3.51 per Mcf, respectively, for natural gas, and \$42.36, \$80.62 and \$84.97 per barrel, respectively, for oil and condensate. As part of the SWEPI Transaction, 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. For 2015 and 2014, the average sales price utilized for purposes of estimating the Company's proved reserves and future net revenues associated with NGLs was $20.61 and $46.27 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.

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,		
	2015	2014	2013
Future cash inflows	$ 6,312,095	$27,331,391	$14,861,131
Future production costs	(3,006,265)	(8,627,657)	(4,540,209)
Future development costs	(358,848)	(3,859,385)	(2,014,751)
Future income taxes	—	(3,898,355)	(1,897,340)
Future net cash flows	2,946,982	10,945,994	6,408,831
Discount at 10%	(1,081,333)	(5,712,511)	(3,220,862)
Standardized measure of discounted future net cash flows	$ 1,865,649	$ 5,233,483	$ 3,187,969

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,		
	2015	2014	2013
Standardized measure, beginning	$ 5,233,483	$ 3,187,969	$ 1,894,317
Net revisions of previous quantity estimates	(2,126,998)	(603,795)	(1,089,316)
Extensions, discoveries and other changes	15,254	1,787,643	2,098,644
Sales of reserves in place	—	(398,506)	—
Acquisition of reserves	—	2,552,491	86,196
Changes in future development costs	1,618,068	(1,013,652)	(252,992)
Sales of oil and gas, net of production costs	(550,879)	(949,389)	(720,826)
Net change in prices and production costs	(6,996,416)	1,010,052	1,204,041
Development costs incurred during the period that reduce future development costs	548,112	342,987	171,149
Accretion of discount	709,736	413,177	226,326
Net changes in production rates and other	1,551,413	(175,419)	145,289
Net change in income taxes	1,863,876	(920,075)	(574,859)
Aggregate changes	(3,367,834)	2,045,514	1,293,652
Standardized measure, ending	$ 1,865,649	$ 5,233,483	$ 3,187,969

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 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,		
	2015	2014	2013
United States			
Property Acquisitions:			
Unproved	$ 13,845	$ 26,106	$ 424,540
Proved	—	895,179	224,410
Exploration*	18,164	197,664	184,007
Development	461,458	382,984	186,755
Total	$493,467	$1,501,933	$1,019,712

* 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,		
	2015	2014	2013
United States			
Oil and gas revenue	$ 839,111	$1,230,020	$ 933,404
Production expenses	(288,231)	(280,631)	(212,578)
Depletion and depreciation	(401,200)	(292,951)	(243,390)
Ceiling test and other impairments	(3,144,899)	—	—
Income tax benefit (expense)	(9,841)	3,736	(2,821)
Total	$(3,005,060)	$ 660,174	$ 474,615

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	December 31, 2015	December 31, 2014
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$10,480,165	$ 9,731,407
Less: accumulated depletion, depreciation and amortization	(9,629,020)	(6,094,764)
	851,145	3,636,643
Unproven Properties:		
Acquisition and exploration costs not being amortized	—	242,294
	$ 851,145	$ 3,878,937

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, 2015	2014	2013
General and administrative expense	$ 308	$ 261	$ 102
Other income (expense):			
Interest expense	(81,069)	(42,996)	(1,438)
Income from unconsolidated affiliates	(3,152,078)	558,634	223,685
Guarantee fee income	23,029	23,045	22,406
Other expense	(1,684)	(1,324)	(1,836)
Income before income taxes	(3,212,110)	537,098	242,715
Income tax (benefit) expense	(4,890)	(5,753)	4,877
Net income	$(3,207,220)	$542,851	$237,838

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONDENSED BALANCE SHEET

	December 31, 2015	December 31, 2014
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 523	$ 772
Accounts receivable from related companies	64,542	33,146
Other current assets	21,918	6,246
Total current assets	86,983	40,164
Investment in unconsolidated affiliates	—	1,461,226
Other non-current assets	24,197	27,339
Total assets	$ 111,180	$1,528,729
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 1,300,000	$ —
Interest payable	14,166	16,046
Accrued and other current liabilities	—	31
Total current liabilities	1,314,166	16,077
Long-term debt	—	1,300,000
Advances to unconsolidated affiliates	1,788,951	—
Other long-term obligations	—	992
Total shareholders' equity	(2,991,937)	211,660
Total liabilities and shareholders' equity	$ 111,180	$1,528,729

CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
Net cash (used in) provided by operating activities	$(101,277)	$ (35,818)	$ 17,772
Investing Activities:			
Investment in subsidiaries	—	(850,000)	(464,405)
Dividends received	96,297	52,741	4,580
Net cash provided by (used in) investing activities	96,297	(797,259)	(459,825)
Financing activities:			
Proceeds from issuance of Senior Notes	—	850,000	450,000
Deferred financing costs	6	(13,245)	(8,958)
Repurchased shares	—	(6,471)	(3,311)
Shares re-issued from treasury	4,725	2,936	1,496
Net cash provided by financing activities	4,731	833,220	439,227
(Decrease) increase in cash during the period	(249)	143	(2,826)
Cash and cash equivalents, beginning of period	772	629	3,455
Cash and cash equivalents, end of period	$ 523	$ 772	$ 629

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 72 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, 2015 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, 2015. 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.***

Amendment to Employment Agreement

On February 24, 2016, but effective for all purposes on February 16, 2016, the Company entered into that certain Second Amendment to Employment Agreement (the "Second Amendment") with Michael D. Watford, Chairman, Chief Executive Officer and President of the Company. The Second Amendment, among other changes set forth therein, provides for the Company to enter into a letter of credit in the amount of $2.0 million, and gives Mr. Watford the right to draw upon the letter of credit if the Company fails to pay the cash severance benefits promised to Mr. Watford upon a Qualifying Termination of Employment (as defined in the Second Amendment). This description of the Second Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Second Amendment, which is filed as an exhibit to this Form 10-K and incorporated by reference herein.

Ultra Petroleum Corp. 2016 Key Employee Incentive Plan

On February 26, 2016, in connection with the adoption of comprehensive new compensation programs for all salaried employees and executive officers of the Company, the Compensation Committee of the Board of Directors of the Company (the "Compensation Committee") adopted the Ultra Petroleum Corp. 2016 Key Employee Incentive Plan (the "Incentive Plan"). It is intended to enable the Company's executive officers to earn performance-based incentive compensation in cash during the 2016 calendar year. All of the Company's executive officers, including its Chief Executive Officer, both of its Senior Vice Presidents, and each of its three Vice Presidents, are participating in the plan. The Incentive Plan replaces the Company's historic annual incentive and long-term incentive compensation plans.

Pursuant to the plan, the Compensation Committee assigned a target incentive award to each participant. The awards were determined by the Committee using competitive market data with the target compensation at a lower percentile (25th) than the Company has historically targeted (50th) for executive compensation. Compensation under the Incentive Plan will be made quarterly based on the achievement of performance goals established by the Committee, although due to the difficulty in timely determining performance metrics and levels for the first quarter of 2016 only, the Committee determined to make payments under the plan based solely on a participant's continued employment with the Company through the end of such quarter. To provide continuous motivation throughout the year, the plan measures the performance metrics on a quarterly and cumulative basis, and performance achievements in excess of the performance metrics during a quarter may result in recovery of payments not received due to performance achievements below the performance metrics during a prior quarter. The plan includes two performance levels: threshold and target. The total amount of payments to a participant under the Incentive Plan may not exceed the amount of such participant's target incentive award. A participant must be employed on the applicable payment date in order to earn a quarterly payment under the plan. The foregoing description of the Incentive Plan is qualified in all respects by the comprehensive plan documents filed herewith.

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, 2015.

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, 2015.

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, 2015.

Item 13. *Certain Relationships and 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, 2015.

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, 2015.

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	Lease dated as of December 20, 2012 between Ultra Wyoming LGS, LLC, a Delaware limited liability company, as Lessee, and Pinedale Corridor, LP, a Delaware limited partnership, as Lessor.
10.11	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).
10.12	Purchase Agreement dated December 6, 2013 between Ultra Petroleum Corp. and Goldman, Sachs & Co., as representative of the Initial Purchasers (as defined therein) (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on December 12, 2013).
10.13	Registration Rights Agreement dated December 12, 2013 between Ultra Petroleum Corp. and Goldman, Sachs & Co., as representative of the Initial Purchasers (as defined therein) (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K filed on December 12, 2013).
10.14	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).
10.15	Purchase Agreement dated September 4, 2014 between Ultra Petroleum Corp. and Goldman, Sachs & Co., as representative of the Initial Purchasers (as defined therein) (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed with the SEC on September 5, 2014).
10.16	Registration Rights Agreement dated September 18, 2014 between Ultra Petroleum Corp. and Goldman, Sachs & Co., as representative of the Initial Purchasers (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K filed with the SEC on September 22, 2014).
*10.17	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.
*10.18	Ultra Petroleum Corp. 2016 Key Employee Incentive Plan adopted effective January 1, 2016 by Ultra Petroleum Corp.
21.1	Subsidiaries of the Company.
*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.
*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, 2015.
*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.

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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 29, 2016

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 29, 2016
/s/ Garland R. Shaw Garland R. Shaw	Senior Vice President and Chief Financial Officer (principal financial officer)	February 29, 2016
/s/ Maree K. Delgado Maree K. Delgado	Corporate Controller (principal accounting officer)	February 29, 2016
/s/ W. Charles Helton W. Charles Helton	Director	February 29, 2016
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 29, 2016
/s/ Roger A. Brown Roger A. Brown	Director	February 29, 2016
/s/ Michael J. Keeffe Michael J. Keeffe	Director	February 29, 2016

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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).
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).
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	Lease dated as of December 20, 2012 between Ultra Wyoming LGS, LLC, a Delaware limited liability company, as Lessee, and Pinedale Corridor, LP, a Delaware limited partnership, as Lessor.
10.11	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).

Table of Contents

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*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

Exhibit 10.17

SECOND AMENDMENT TO EMPLOYMENT AGREEMENT

THIS SECOND AMENDMENT TO EMPLOYMENT AGREEMENT (this "Amendment") is made and entered into by and between Michael D. Watford ("Watford"). Ultra Petroleum Corp., a Yukon corporation and each of the Company's subsidiaries, including: UP Energy Corporation and Ultra Resources, Inc. (the "Company"), dated as of February 24, 2016 effective as of February 16, 2016 for purposes of amending that certain employment agreement by and between Watford and the Company, dated February 1, 2007 (the "Employment Agreement"). Terms used in this Amendment with initial capital letters that are not otherwise defined herein shall have the meanings ascribed to such terms in the Employment Agreement.

WHEREAS, the Company and Watford are party to the Employment Agreement dated as of February 1, 2007 (the "Employment Agreement");

WHEREAS, Section 1 of the Employment Agreement provides that the term of Watford's employment under the Employment Agreement is automatically extended (an "Extension") each February 1 unless the Company Board provides ninety (90) days advance notice of its intention not to renew such employment (a "Non-Renewal Notice");

WHEREAS, the Company has not provided a Non-Renewal Notice so that the term of Watford's employment under the Employment Agreement has been extended for the one-year period commencing February 1, 2016;

WHEREAS, Section 1 and Section 4.B of the Employment provide that Watford may unilaterally elect to terminate his employment if an agreement cannot be reached as to the terms of any Extension and, in the event of any such termination, Watford would be entitled to the severance benefits specified in Section 4.B of the Employment Agreement;

WHEREAS, as of the date of this Amendment, the Company has not offered Watford satisfactory terms of employment during the Extension, including satisfactory levels of annual and long-term compensation;

WHEREAS, the Company desires for Watford not to terminate his employment pursuant to Section 1 and Section 4.B of the Employment Agreement;

WHEREAS, subject to the terms and conditions hereof, and in consideration for the contemporaneous posting of the Letter of Credit (defined below), Watford is willing to forgo his right to terminate his employment pursuant to Section 1 and Section 4.B of the Employment Agreement; and

WHEREAS, the Company acknowledges that Watford agreeing to forgo his right to terminate his employment contemporaneously with the Company's providing the Letter of Credit provides substantial and new value to the Company and the Company's subsidiaries.

NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby acknowledged by the parties, the Company and Watford hereby agree as follows.

1. Waiver of Certain Termination Rights. Subject to the terms and conditions hereof, Watford hereby irrevocably waives his right to terminate his employment pursuant to Section 1 and Section 4.B of the Employment Agreement in connection with the Extension that occurred on February 1, 2016. For the sake of clarity, Watford is not waiving the right to terminate his employment pursuant to Section 1 and Section 4.B in connection with any future extension of his employment pursuant to the Employment Agreement.

2. Letter of Credit. In consideration of Watford's waiver of his termination rights under Section 1 of this Amendment, the Company agrees that promptly after the date hereof, and in any event within 10 days hereof, it shall enter into an irrevocable letter of credit with a bank of national standing reasonably acceptable to Watford in the amount of $2,000,000 (the "Letter of Credit"), which is the amount of severance Watford would be entitled to if he exercised his rights to terminate his employment pursuant to Section 1 and Section 4.B of the Employment Agreement. Watford may and shall be entitled to draw upon the Letter of Credit if he has a Qualifying Termination of Employment (as defined below) and the Company fails for any reason to pay 100% of the cash severance benefits otherwise payable under the Employment Agreement with respect to such Qualifying Termination of Employment, it being acknowledged and agreed that Watford may draw upon the Letter of Credit only to the extent the Company fails to pay such cash severance benefits. For purposes hereof, a "Qualifying Termination of Employment" means a termination of Watford's employment with the Company pursuant to Section 4.A, Section 4.B, Section 4.C or Section 4.D of the Employment Agreement; provided that Watford may not draw upon the Letter of Credit for any termination pursuant to Section 4.B of the Employment Agreement unless Watford provides notice to the Company no later than January 1 immediately preceding the Extension (e.g., by January 1, 2017 for an Extension occurring on February 1, 2017) that he intends to terminate his employment pursuant to Section 4.B of the Employment Agreement if mutually satisfactory terms of employment are not reached by such February 1. The Letter of Credit shall expire upon the satisfaction of all obligations to Watford under this Amendment.

3. Ratification of Employment Agreement. Except as expressly provided in this Amendment, the Employment Agreement is hereby ratified and affirmed and remains in full force and effect.

4. Benefit and Binding Effect. The Amendment shall inure to the benefit of, and be binding upon, the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the parties have executed this Amendment intending it to be effective on the date first indicated above.

COMPANY:

ULTRA PETROLEUM CORP.

By: */s/ Wm. Charles Helton*
Name: Dr. Wm. Charles Helton
Title: Chairman, Compensation Committee

/s/ Michael D. Watford
Michael D. Watford

Exhibit 10.18

ULTRA PETROLEUM CORP.
2016 KEY EMPLOYEE INCENTIVE PLAN

1. Purpose. This Ultra Petroleum Corp. (the "Company") 2016 Key Employee Incentive Plan (the "Plan") is designed to align the interests of the Company and eligible key employees of the Company and its subsidiaries.

2. Adoption of the Plan. The Company, intending to be legally bound, hereby adopts the Plan effective as of January 1, 2016 (the "Effective Date"). The Plan shall be in effect from the Effective Date and shall continue until December 31, 2016 (the "Term"). The expiration of the Term shall not in any event reduce or adversely affect any amounts due to any Participant hereunder.

3. General. The compensation provided under the Plan is intended to be in addition to all other compensation payable to Participants under any employment agreement or incentive plan or program in effect with the Company or its direct or indirect subsidiaries.

4. Definitions. For purposes of this Plan:

(a) "Board" means the Company's Board of Directors.

(b) "Committee" means any committee authorized by the Board to administer the Plan. If no committee is duly authorized by the Board to administer the Plan, the term "Committee" shall be deemed to refer to the Board for all purposes of the Plan.

(c) "Company Group" means the Company and its direct and indirect subsidiaries.

(d) "Participant" shall have the meaning ascribed thereto in Section 5 hereof.

(e) "Performance Goals" means the Performance Metric (as defined below) goals set forth on Schedule A, as follows: (i) Quarterly Threshold Performance Goals, (ii) Quarterly Target Performance Goals, (iii) Cumulative Threshold Performance Goals and (iv) Cumulative Target Performance Goals.

(f) "Performance Metrics" means the performance metrics used to measure the Company's performance under the Plan as set forth on Schedule A.

(g) "Quarter" means each calendar quarter commencing during the Term, specifically: January 1, 2016 through March 31, 2016 ("First Quarter"), April 1, 2016 through June 30, 2016 ("Second Quarter"), July 1, 2016 through September 30, 2016 ("Third Quarter"), and October 1, 2016 through December 31, 2016 ("Fourth Quarter").

(h) "Quarterly Performance Incentive" shall mean, in the case of any Participant, the incentive payable to such Participant under the Plan for the applicable Quarter.

(i) "Quarterly Performance Incentive Amount" shall mean, in the case of any Participant, the amount of the Quarterly Performance Incentive for such Participant as set forth on Schedule A.

5. Eligible Participants. Each person listed on Schedule A, as amended from time to time by the Board or the Committee, shall be a Participant under the Plan and eligible to receive a Quarterly Performance Incentive with respect to each Quarter.

6. Term of Participation.

(a) Subject to the provisions of this Plan, each Participant shall earn a Quarterly Performance Incentive as of the end of each Quarter, equal to all or a portion of the Quarterly Performance Incentive Amount, depending upon the extent to which the Performance Goals set forth in Schedule A have been achieved for such

Quarter; provided that with respect to the First Quarter only, a Participant shall earn 100% of the Quarterly Performance Incentive Amount, subject to such Participant's continuous employment with the Company Group through the Quarterly Performance Incentive payment date for the First Quarter.

(b) In addition to being measured on a Quarterly basis, the Performance Goal for each Performance Metric shall be measured cumulatively from the beginning of the Second Quarter through the end of each of the Third and Fourth Quarters.

(i) Third Quarter Catch-Up: A Participant shall earn, in addition to any Quarterly Performance Incentive payable for the Third Quarter pursuant to Section 6(a) above, an amount equal to (i) the aggregate Quarterly Performance Incentive Amount payable based on achievement of the Cumulative Performance Goal as of the end of the Third Quarter, minus (ii) the Quarterly Performance Incentive Amount actually paid for the Second Quarter, if any, and payable for the Third Quarter pursuant to Section 6(a) above.

(ii) Fourth Quarter Catch-Up: A Participant shall earn, in addition to any Quarterly Performance Incentive payable for the Fourth Quarter pursuant to Section 6(a) above, an amount equal to (i) the aggregate Quarterly Performance Incentive Amount payable based on achievement of the Cumulative Performance Goal as of the end of the Fourth Quarter, minus (ii) the Quarterly Performance Incentive Amount actually paid for the Second and Third Quarters, if any, and payable for the Fourth Quarter pursuant to Section 6(a) above.

(c) If the Term ends after the commencement, and before the end, of a Quarter, each Participant who is then employed by the Company shall earn a prorated amount of the Quarterly Performance Incentive for the Quarter in which the Term ends (based on the portion of the Quarter that has elapsed as of the last day of the Term), and the Participant shall not be eligible to earn a Quarterly Performance Incentive following the Term.

(d) Any Quarterly Performance Incentive required to be made under this Plan shall be paid by the Company within 45 days after the end of the applicable Quarter.

(e) In order to earn a Quarterly Performance Incentive for any Quarter, a Participant must remain employed by the Company Group through the Quarterly Performance Incentive payment date with respect to such Quarter. A Participant whose employment with the Company Group terminates for any reason shall forfeit the right to any Quarterly Performance Incentive that has not been paid as of the date of such termination.

7. Performance Goals. Promptly after the end of each Quarter (but in any event within 30 days of the end of the Quarter), the Committee shall certify the degree to which the applicable Performance Goals have been achieved and the amount payable to each Participant hereunder.

8. Plan Administration. This Plan shall be administered by the Committee. The Committee is given full authority and discretion within the limits of this Plan to establish such administrative measures as may be necessary to administer and attain the objectives of this Plan and may delegate the authority to administer the Plan to an officer of the Company. The Committee (or its delegate, as applicable) shall have full power and authority to construe and interpret this Plan and any interpretation by the Committee shall be binding on all Participants and shall be accorded the maximum deference permitted by law.

(a) All rights and interests of Participants under this Plan shall be non-assignable and nontransferable, and otherwise not subject to pledge or encumbrance, whether voluntary or involuntary, other than by will or by the laws of descent and distribution. In the event of any sale, transfer or other disposition of all or substantially all of the Company's assets or business, whether by merger, stock sale, consolidation or otherwise, the Company may assign this Plan.

(b) Any payment to a Participant in accordance with the provisions of this Plan shall, to the extent thereof, be in full satisfaction of all claims against the Company Group, and the Company may require Employee, as a condition precedent to such payment, to execute a receipt and release to such effect.

(c) Payment of amounts due under the Plan shall be provided to Participant in the same manner as Participant receives his or her regular paycheck or by mail at the last known address of Participant in the possession of the Company, at the discretion of Committee. The Company will deduct all applicable taxes and any other withholdings required to be withheld with respect to the payment of any award pursuant to this Plan.

(d) The Company shall not be required to establish any special or separate fund or to make any other segregation of assets to ensure the payment of any award provided for hereunder. Quarterly Performance Incentive payments shall not be considered as extraordinary, special incentive compensation, and it will not be included as "earnings," "wages," "salary," or "compensation" in any pension, welfare, life insurance, or other employee benefit plan or arrangement of the Company Group.

(e) The Company, in its sole discretion, shall have the right to modify, supplement, suspend or terminate this Plan at any time; provided that in no event shall any amendment or termination adversely affect the rights of Participants regarding any Quarterly Performance Incentive for a Quarter that has commenced as of the date of such action without the prior written consent of the affected Participants. Subject to the foregoing, the Plan shall terminate upon the satisfaction of all obligations of the Company or its successor entities hereunder.

(f) Nothing contained in this Plan shall in any way affect the right and power of the Company to discharge any Participant or otherwise terminate his or her employment at any time or for any reason or to change the terms of his or her employment in any manner.

(g) Except as otherwise provided under this Plan, any expense incurred in administering this Plan shall be borne by the Company.

(h) Captions preceding the sections hereof are inserted solely as a matter of convenience and in no way define or limit the scope or intent of any provision hereof.

(i) The administration of the Plan shall be governed by the laws of the State of Texas, without regard to the conflict of law principles of any state. Any persons or corporations who now are or shall subsequently become parties to the Plan shall be deemed to consent to this provision.

(j) The Plan is intended to either comply with, or be exempt from, the requirements of Section 409A of the Internal Revenue Code of 1986, as amended ("Code Section 409A"). To the extent that the Plan is not exempt from the requirements of Code Section 409A, the Plan is intended to comply with the requirements of Code Section 409A and shall be limited, construed and interpreted in accordance with such intent. Notwithstanding the foregoing, in no event whatsoever shall the Company be liable for any additional tax, interest, income inclusion or other penalty that may be imposed on a Participant by Code Section 409A or for damages for failing to comply with Code Section 409A.

* * * * *

SCHEDULE A

1. List of Participants and Quarterly Incentive Amounts

Participant	Quarterly Performance Incentive Amount
Michael Watford - Chairman, President & CEO	$832,500
Garland Shaw - SVP & CFO	$399,250
Brad Johnson - SVP Operations	$294,250
Kent Rogers - VP Drilling & Completions	$163,000
Douglas Selvius - VP Exploration	$122,750
Garrett Smith - VP & GC	$225,380

2. Performance Metrics and Goals

(a) Quarter Ending March 31, 2016. Not applicable. Quarterly Performance Incentive Amount earned in accordance with Section 6(a) of the Plan.

(b) Quarters Ending June 30, 2016, September 30, 2016 and December 31, 2016:

The portion of the Quarterly Performance Incentive Amount that is contingent upon a Performance Metric is the "Applicable Portion."

Portion of Applicable Portion Payable if Quarterly and/or Cumulative Threshold Performance Goal Achieved:	65%
Portion of Applicable Portion Payable if Quarterly and/or Cumulative Target Performance Goal Achieved:	100%
Portion of Applicable Portion Payable if Achievement is Between Quarterly and/or Cumulative Threshold and Target Performance Goals:	Linear interpolation between 65% and 100%

(i) **Performance Metric:** Production (measured in billion cubic feet equivalent)

Applicable Portion: 33.33%

Quarter Ending:	June 30, 2016	September 30, 2016	December 31, 2016
Quarterly Threshold Performance Goal	66.0	65.0	64.0
Quarterly Target Performance Goal	69.5	68.5	68.0
Cumulative Threshold Performance Goal	66.0	131.0	195.0
Cumulative Target Performance Goal	69.5	138.0	206.0

(ii) **Performance Metric:** Cash Costs/mcfe* (determined as a weighted average)

Applicable Portion: 33.33%

Quarter Ending:	June 30, 2016	September 30, 2016	December 31, 2016
Quarterly Threshold Performance Goal	$ 1.39	$ 1.45	$ 1.51
Quarterly Target Performance Goal	$ 1.25	$ 1.30	$ 1.35
Cumulative Threshold Performance Goal	$ 1.39	$ 1.42	$ 1.45
Cumulative Target Performance Goal	$ 1.25	$ 1.28	$ 1.30

* mcfe (million cubic feet equivalent): Calculation excludes interest expense and all restructuring costs.

(iii) **Performance Metric:** Capital Expenditures in millions of USD

Applicable Portion: 33.33%

Quarter Ending:	June 30, 2016	September 30, 2016	December 31, 2016
Quarterly Threshold Performance Goal	$ 73.5	$ 70.0	$ 66.5
Quarterly Target Performance Goal	$ 66.0	$ 62.0	$ 60.0
Cumulative Threshold Performance Goal	$ 73.5	$ 143.5	$ 210.0
Cumulative Target Performance Goal	$ 66.0	$ 128.0	$ 188.0

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued a report, as of December 31, 2015, 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, 2015" 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 5, 2016, 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), Form S-4 (File No. 333-199485; 333-206679) and Form S-3 (File No. 333-200916; 333-202256; 333-207028).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ G. Lance Binder, P.E.
G. Lance Binder, P.E.
Executive Vice President

Dallas, Texas
February 29, 2016

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-4 No. 333-199485) of Ultra Petroleum Corp.,
(4) Registration Statement (Form S-3 Shelf Registration No. 333-200916) of Ultra Petroleum Corp.,
(5) Registration Statement (Form S-3 Shelf Registration No. 333-202256) of Ultra Petroleum Corp.,
(6) Registration Statement (Form S-8 No. 333-202307) pertaining to the Ultra Petroleum Corp. 2015 Stock Incentive Plan,
(7) Registration Statement (Form S-4 No. 333-206679) of Ultra Petroleum Corp., and
(8) Registration Statement (Form S-3 Shelf Registration No. 333-207028) of Ultra Petroleum Corp.;

of our reports dated February 29, 2016, with respect to the consolidated financial statements of Ultra Petroleum Corp. (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. included in this Annual Report (Form 10-K) of Ultra Petroleum Corp. for the year ended December 31, 2015.

/s/ Ernst & Young LLP
Houston, Texas
February 29, 2016

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 29, 2016

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 29, 2016

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, 2015, 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 29, 2016

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, 2015, 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 29, 2016

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 5, 2016

Mr. W. Patrick Ash
Ultra Petroleum Corp.
304 Inverness Way South, Suite 295
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, 2015, 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, 2015, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	**Oil (MBBL)**	**NGL (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	21,345.7	9,677.6	2,242,421.8	2,807,703.1	1,784,092.2
Proved Developed Non-Producing	829.6	161.9	93,858.3	139,279.2	81,557.1
Total Proved Developed	22,175.3	9,839.5	2,336,280.1	2,946,982.4	1,865,649.3

Totals may not add because of rounding.

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 2015. For oil and NGL volumes, the average spot price is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average regional 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 $42.36 per barrel of oil, $20.61 per barrel of NGL, and $2.213 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	1.178	1.216
Utah	West Texas Intermediate	50.28	37.35	21.84	Northwest (south of Green River)	2.399	1.860
Wyoming	West Texas Intermediate	50.28	43.77	20.60	Kern River (Opal plant)	2.459	2.260

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.

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 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. Robert C. Barg, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1989 and has over 6 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/ Robert C. Barg
Robert C. Barg, P.E. 71658
Senior Vice President

Date Signed: February 5, 2016

By: /s/ Philip R. Hodgson
Philip R. Hodgson, P.G. 1314
Vice President

Date Signed: February 5, 2016

SAM:CDC

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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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.

(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) Ext*ension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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.

(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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.